CANADA

NATIONAL ENERGY BOARD
REASONS FOR DECISION

In the Matter of an Application under Part III
of the National Energy Board Act

of

Trans Québec & Maritimes Pipeline Inc.

July 1981

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Ce rapport est publié
dans les deux langues
officielles.

NATIONAL ENERGY BOARD

IN THE MATTER OF the National Energy Board Act and the Regulations made thereunder;

AND IN THE MATTER OF an application made by Trans Québec & Maritimes Pipeline Inc. for a certificate of Public Convenience and Necessity under Part III of the National Energy Board Act, filed with the Board under File No. 1555-T28-1.

Heard at Ottawa, Ontario, on 10, 11, 12, 13, 16, 17, 18, 19, 20, 23, 24, 25, 26, and 27 March 1981; Fredericton, New Brunswick on 30 and 31 March 1981; Halifax, Nova Scotia on 1 and 2 April 1981; Quebec City, Quebec on 6 April 1981; Ottawa, Ontario on 8, 9, 10, 13, 14, 15, 21, 22, 23 and 24 April 1981.

BEFORE:

C.G. Edge	Presiding Member
J. Farmer	Member
A.B. Gilmour	Member

APPEARANCES:

J. Hopwood, Q.C. P. McCarthy A. Nadon	Trans Québec & Maritimes Pipeline Inc.
J. Michaud R. Ouellet	Association des agents pour le développement économique de l'est du Québec
D.B. Macnamara	Canadian Petroleum Association
C.K. Yates A.E. Potter	Independent Petroleum Association
B. Carroll	Industrial Gas Users Association
P. Walsh	Mechanical Contractors Association of New Brunswick and United Association of Plumbers and Pipefitters
E. Ryan	Imperial Oil Limited
J.B. McWilliams	Mobil Oil Canada, Ltd.
J.J. Marshall	Norcen Energy Resources Limited

P. Bretzloff	Petro-Canada
W.F. Muscoby	Texaco Canada
D.G. Hart, Q.C. J. Hope-Ross R.H. Mackie	PanCanadian Petroleum Limited
R. Pepper	Alberta and Southern Gas Co. Ltd.
R. DesBrisay	Blakeny and Son (1979) Ltd.
J.M. Hanson	Fraser Inc.
Y. Brisson	Gaz Inter-Cité Québec Inc.
M. Peterson C. Messier L. Martin	Gaz Métropolitain, inc.
J.D. Brett	Inter-City Gas Corporation
D. Case	ICG Brunswick Gas Ltd.
J.C. Scobie M.G. Meacher	ICG Scotia Gas Ltd.
J. Coombs	New Brunswick Telephone Company
D.B. O'Brien, Jr.	Northern Border Pipeline Company
E.B. McDougall	Northwest Alaskan Pipeline Company
K.F. Keeler	Pan-Alberta Gas Ltd.
D.G. Hart, Q.C.	ProGas Limited
W.T. Houston	Tennessee Gas Pipeline Company A Division of Tenneco Inc.
J.H. Farrell	The Consumers' Gas Company A Division of Hiram Walker-Consumers Home Ltd.
T. Dalgleish J. Murray	TransCanada PipeLines Limited
W.G. Burke-Robertson	Transcontinental Gas Pipe Line Corporation and Algonquin Gas Transmission Company
D.E. Wires	Ultramar Canada Inc.
A. Mudryj	Union Gas Limited

W. Crain	)	United Gas Pipe Line Company
W. Crain	))	United Mid-Continent Pipeline Company
W. Green R.W. Douglas	))	Woodex Atlantic Ltd.
W.J. Lea	)	Maritime Electric Company Limited
F.M. Saville	))	Alberta Petroleum Marketing Commission
A. Joncas	)))	La Corporation de promotion industrielle de la région de Rivière-du-Loup
L. Marquis	))	Conseil régional de développement de l'est du Québec
S. LeBlanc	)	Fredericton Chamber of Commerce
H. Giddens	)	Halifax Board of Trade
D. Hoyt J. Daigle	))	Liberal Party of New Brunswick
P.A. MacNutt D.A.I. Wright	))	The New Brunswick Electric Power Commission
T. Demma	))	New Brunswick Federation of Agriculture
T.H. Good	))	New Brunswick New Democratic Party
A. LeBlanc	))	Strait of Canso Industrial Development Authority
C. Nicholas	)	Union of New Brunswick Indians
W.F. Denny P.A. MacNutt D.A.I. Wright	)))	Government of New Brunswick
N. Hall	))	Government of Prince Edward Island
J.M. Johnson	)	Minister of Energy for Ontario
M.J. Veniot	)	Province of Nova Scotia
J. Giroux	)	Procureur général du Québec
A. Bigué	)	National Energy Board

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ABBREVIATIONS

FOR NAMES:

"Act"	-	National Energy Board Act
"AERCB"	-	Alberta Energy Resources Conservation Board
"APMC"	-	Alberta Petroleum Marketing Commission
"ADEQ"	-	Association des agents pour le développement économique de l'est du Québec
"Consumers'"	-	The Consumers' Gas Company A Division of Hiram Walker - Consumers Home Ltd.
"CPA"	-	Canadian Petroleum Association
"CPIR"	-	Corporation de promotion industrielle de la région de Rivière-du-Loup
"CRDEQ"	-	Conseil régional de développement de l'Est du Québec
"EMR"	-	Energy, Mines & Resources Canada
"ICG Brunswick"	-	ICG Brunswick Gas Ltd.
"ICG Scotia"	-	ICG Scotia Gas Limited
"IGUA"	-	Industrial Gas Users Association
"Inter-City"	-	Inter-City Gas Corporation
"IPAC"	-	Independent Petroleum Association of Canada
"Mobil"	-	Mobil Oil Canada, Ltd.
"NBFA"	-	New Brunswick Federation of Agriculture
"NB Power"	-	The New Brunswick Electric Power Commission
"NEP"	-	National Energy Program
"New Brunswick"	-	Government of New Brunswick
"Norcen"	-	Norcen Energy Resources Limited
"NOVA"	-	NOVA, AN ALBERTA CORPORATION
"Nova Scotia"	-	The Province of Nova Scotia

"Ontario"	-	Minister of Energy of the Province of Ontario
"Pan-Alberta"	-	Pan-Alberta Gas Ltd.
"PanCanadian"	-	PanCanadian Petroleum Limited
"Quebec"	-	Procureur général du Québec
"Q & M"	-	Q & M Pipe Lines Ltd.
"SOQUIP"	-	La Société Québécoise d'Initiatives Pétrolières
"TCPL"	-	TransCanada PipeLines Limited
"TQM" or "Applicant"	-	Trans Québec & Maritimes Pipeline Inc.
"UNBI"	-	Union of New Brunswick Indians

FOR TERMS:

"CD"	-	Contract Demand
"m^3"	-	Cubic metre
"GJ"	-	Gigajoule (10^9 joules)
"ha"	-	Hectare
"km"	-	Kilometre
"kPa"	-	Kilopascal
"kv"	-	Kilovolt
"kW"	-	Kilowatt
"m"	-	Metre
"mm"	-	Millimetre
"PJ"	-	Petajoule (10^{15} joules)

CHAPTER 1

APPLICATION AND CIRCUMSTANCES SURROUNDING IT

1.1 April 1980 Decision. During a public hearing that concluded on 30 January 1980, the Board heard evidence concerning an application by TCPL to extend its natural gas pipeline from Montreal to Lévis/Lauzon and an application by Q & M to build a natural gas pipeline from Lévis/Lauzon to Halifax.

The Board found that the pipeline facilities applied for by TCPL, with certain exceptions, were required by the present and future public convenience and necessity and authorized their construction and operation by issuing Certificates GC-64 and 65.

The Board denied the Q & M application and, in doing so, stated in its April 1980 Reasons for Decision at pages 6-126 and 6-127:

> "The Board concludes that Q & M has not satisfied the Board that this line would be constructed in, '...an environmentally acceptable manner,' nor that it would achieve, as the Company states, '...a high level of environmental compatibility.'
>
> "It is apparent that Q & M would have to undertake considerable additional work in order to assure the Board that the environment would be adequately protected during the construction and operation of the proposed pipeline."

At page 11-10 it stated:

> "The Board....finds that the viability of the Q & M project alone cannot be reasonably assured..., and some further incentive pricing measures would have to be put in place to assure the economic viability of the distributors and thus of the proposed Q & M project itself."

Also at page 11-10 it stated:

> "The Board is not satisfied that Q & M has given adequate consideration to the impact on its project of oil and gas developments in the offshore areas of eastern Canada.

> "The Board believes that the evidence adduced on offshore resources raises significant uncertainties as to the configuration of the Q & M pipeline."

The Board concluded that it could not recommend the issuance of a certificate of public convenience and necessity to Q & M in that it was not satisfied that the pipeline facilities proposed to be built and operated by Q & M were and would be required by the present and future public convenience and necessity.

1.2 Nova Scotia Application for Review. In an application dated 22 July 1980, the Government of Nova Scotia requested a review, pursuant to section 17 of the National Energy Board Act, of the April 1980 decision of the Board to deny the application of Q & M for a certificate, and that the decision be amended to grant a certificate to Q & M.

After careful consideration of the application, written comments from parties of record, and Nova Scotia's further reply dated 9 October 1980, the Board concluded that a sufficient case had not been made to justify a review of its decision of April 1980.

1.3 National Energy Program. The NEP, which was announced by the Government of Canada in October 1980, set out a number of measures that were referred to at the hearing of the TQM application. Since these measures were discussed and debated at length during the hearing, it can be of assistance to summarize them here. The NEP included a statement that the government wishes the natural gas pipeline to be extended into the Maritimes, that the pipeline should be reversible to allow probable Atlantic gas resources to be transmitted westwards, that a new pricing policy would be established to provide city-gate prices in the Maritimes at the same level as in southern Ontario and Quebec, that the price of natural gas as

a proportion of the price of oil would be brought down significantly over time to encourage the substitution of gas for oil, that the Government of Canada would set aside up to $500 million to support both the eastern Canada system expansion and the new line to Vancouver Island, that the Government would offer market development bonuses to ensure that expansion of the natural gas distribution systems proceeds rapidly, that the price of oil would be allowed to rise to levels that would make other fuels attractive, and that a program of incentives would be implemented to assist homeowners and businesses to convert from oil.

Before the opening of the hearing, Consumers' raised the question of the effect of the NEP on the Board's proceedings. At the commencement of the hearing, the Board stated as follows:

> "The Board wishes to make it clear that the federal government policy, as expressed in the National Energy Program or elsewhere, does not bind the Board to a decision in these proceedings. Of course, the federal government policy, as expressed in the National Energy Program or elsewhere, although not binding the Board to a decision on this application, may be seen as relevant in these proceedings."

On the opening day, IPAC also raised a number of questions as to how the NEP would be treated in relation to the application in the course of the hearing. The Board ruled in part that:

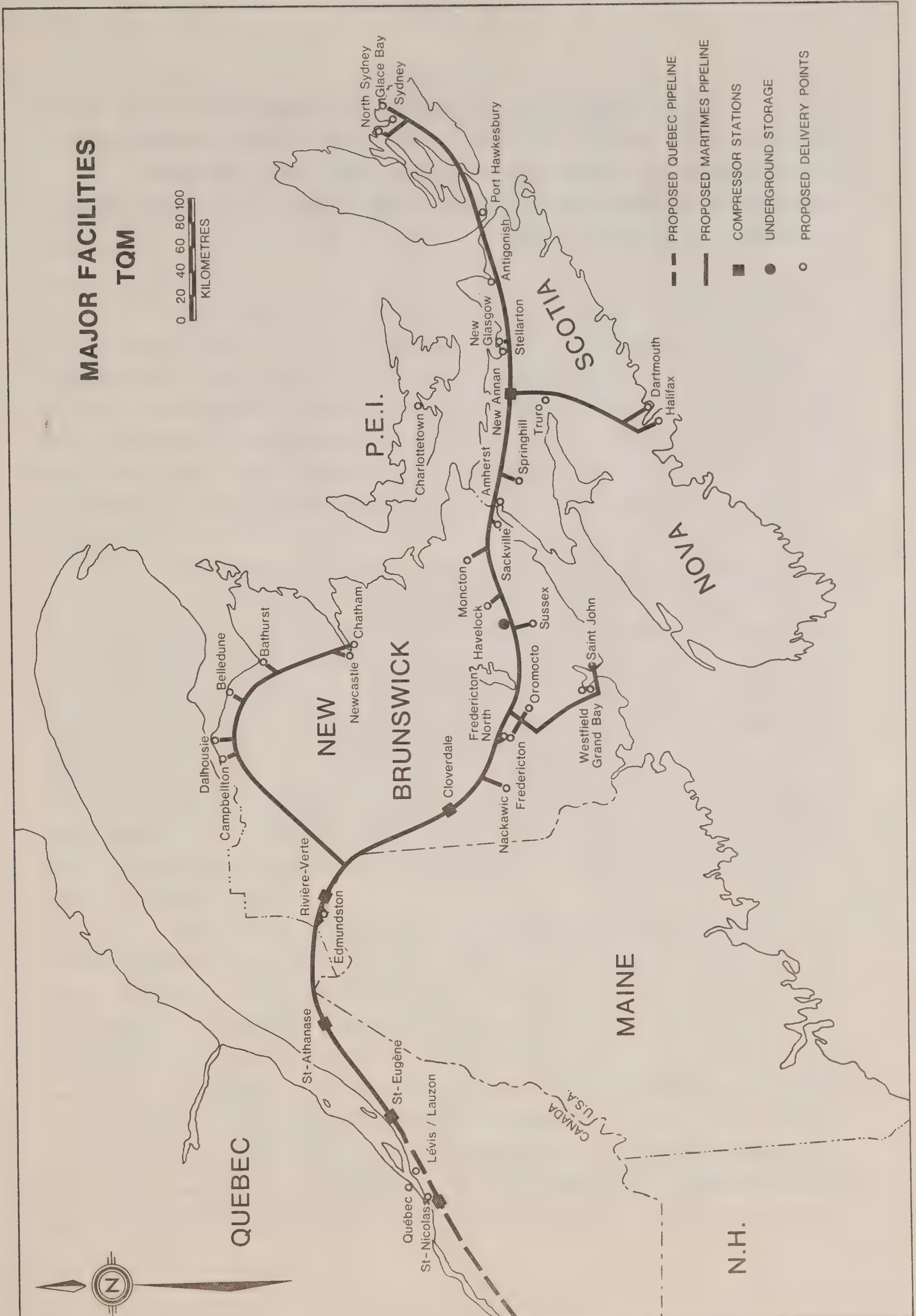
> "The National Energy Program does not remove the burden of the Applicant to prove his case. Insofar as the case of the Applicant is perceived to rest on the National Energy Program, the Intervenors can test that.
>
> "To the extent that greater precision can be given as to how the National Energy Program may affect issues related to the proposed TQM pipeline, the Board would find such clarification helpful."

1.4 Policy Statement on Domestic Pricing. The policy statement on domestic natural gas pricing released by the Minister of Energy, Mines and Resources on 14 April 1981, amplified the natural gas pricing policy set out in the NEP. The existing eastern zone would be extended, making the natural gas price in markets east of Toronto the same as the price at the Toronto city-gate for the same type of gas service. In determining the imputed Alberta border price, TCPL and TQM would be considered as one integrated pipeline system.

1.5 Application. Trans Québec & Maritimes Pipeline Inc. is a company incorporated under the provisions of the Canada Business Corporations Act. All of TQM's shares at the time the application was heard were held in equal proportion by TCPL and Q & M, which is a subsidiary of NOVA.

On 19 December 1980, TQM applied to the Board for a certificate of public convenience and necessity under Part III of the National Energy Board Act to construct and operate natural gas pipeline facilities extending from Lévis/Lauzon, Quebec into the Provinces of New Brunswick and Nova Scotia, to Halifax.

The proposed TQM pipeline system, a map of which is shown as Figure 1-1, would consist of 1743.5 km of mainline and laterals, involving a total cost in 1980 dollars of about $394 million. These facilities would follow the same route as the pipeline previously proposed by Q & M. Initially, they would transport natural gas from western Canada, but would be designed in a way that would facilitate economic reversal of flow and thus could be readily available, when required, for the transmission of gas from east to west. Although underground storage facilities are not part of the present application, the design of the TQM pipeline is based on the use of underground storage by the system's fourth operating year.


MAJOR FACILITIES
TQM
0 20 40 60 80 100
KILOMETRES
PROPOSED QUÉBEC PIPELINE
PROPOSED MARITIMES PIPELINE
COMPRESSOR STATIONS
UNDERGROUND STORAGE
PROPOSED DELIVERY POINTS
QUEBEC
NEW BRUNSWICK
P.E.I.
NOVA SCOTIA
MAINE
N.H.
CANADA
U.S.A.
Québec
St-Nicolas
Lévis / Lauzon
St-Eugène
St-Athanase
Edmundston
Rivière-Verte
Campbellton
Dalhousie
Belledune
Bathurst
Newcastle
Chatham
Cloverdale
Nackawic
Fredericton
Fredericton North
Oromocto
Westfield
Grand Bay
Saint John
Havelock
Sussex
Moncton
Sackville
Amherst
Springhill
Charlottetown
Truro
New Annan
New Glasgow
Stellarton
Antigonish
Port Hawkesbury
Dartmouth
Halifax
North Sydney
Glace Bay
Sydney

By Order GH-1-81 issued on 8 January 1981, the Board provided for a public hearing of the application by TQM. The hearing began in Ottawa on 10 March 1981 and, following sessions in Fredericton, Halifax, and Quebec City, concluded in Ottawa on 24 April 1981.

CHAPTER 2
SUMMARY OF REASONS FOR DECISION

The Board's reasons for decision are summarized in this chapter and are amplified in later chapters of these Reasons for Decision, where the relevant evidence is also summarized.

The Board finds that it had before it sufficient evidence to make a determination on the question of public convenience and necessity of the pipeline facilities applied for by Trans Québec & Maritimes Pipeline Inc. On the basis of such evidence and argument presented by all parties, the Board has found that the applied-for facilities are and will be required by the present and future public convenience and necessity.

The Board realizes that it did not have before it all of the information relating to the manner in which the pipeline will be designed, constructed, and financed, nor did the Board have executed contracts for the supply, transportation, and sale of natural gas to the Maritimes. Furthermore, during the hearing, many references were made to and much reliance was put on certain provisions of the National Energy Program and the further policy statements of the Federal Government, which, the Board is fully aware, have not yet been legislated or implemented in any way that gives them force of law.

It is with this state of awareness and understanding and in taking into account all such matters as appeared to it to be relevant that the Board has found that it had enough evidence to determine the application and has reached its conclusion that the pipeline should be built. The question of security of supply is central to the Board's decision. In the Board's view, the pipeline should be built because the TQM project is an important means of protecting the Maritimes against possible interruptions in the supply of imported crude oil. The Board considers the contribution of the TQM project

towards security of supply to be significant and finds this to be in the public interest.

Under the scheme of the National Energy Board Act, the Board has a continuing supervisory duty that will enable it to control those aspects of the project where details are yet to be completed or resolved. For that purpose, the Board has attached such terms and conditions as it considers necessary to give effect to the purposes and provisions of the Act and to help it to discharge its continuing supervisory duty over the construction and operation of the pipeline. In light of the concerns expressed by certain intervenors of record, and because the Board feels that intervenors can make a valuable contribution toward assessing some of the information to be filed in compliance with these terms and conditions, the Board will provide for input by parties of record with respect to compliance with certain of these conditions.

The Board's concerns when it denied the earlier application by Q & M have been removed or clarified. The measures contained in the National Energy Program and TQM's proposal, brought forward during the hearing, for contributions by the Federal Government and tariff proposals by itself, provide a suitable economic environment for the pipeline which was not previously prevailing. New evidence on environmental matters has led the Board to find that the environmental impact of the project can be mitigated, subject to implementation of appropriate measures. The role of Sable Island gas remains uncertain. The Applicant had carried out further evaluation, but had concluded that it should not apply at this time for facilities designed to accommodate Sable Island gas. In the view of the Board, certification of the pipeline should not be delayed because of this, since the Board's decision is based on the urgent matter of security of supply. Furthermore, the sooner the pipeline is built, the greater the protection against inflation.

With respect to the market for natural gas in New Brunswick and Nova Scotia, the Board notes that the NEP and the subsequent policy statement by the Minister in April 1981 provide for the same price as in Toronto for natural gas in all Canadian markets east of Toronto for the same type of service. The NEP also contemplates the reduction of competition from heavy fuel oil and sets out incentives for the project in terms of a contribution to the cost of construction of the gas transmission line, market development bonuses, and furnace conversion grants to home owners. In the Board's view, the incentives contained in the NEP or other equivalent provisions will be necessary for TQM's natural gas sales forecast to materialize. Moreover, some strengthening of the federal conversion grants or supplementary assistance by the gas distributor to the householder may be necessary to reach TQM's forecast level of conversion of residences to gas.

The rate at which gas will penetrate the market will depend in large measure on the precise steps taken by the government to back out heavy fuel oil. Other factors which will affect the rate of attachment of gas markets will be the proposed construction schedule, the timeliness of appointment of gas distributors, and the aggressiveness of these distributors in developing the market. Because of the low load factors associated with the establishment of new markets, a development price for natural gas, or something akin to it, appears to the Board to be essential for market development.

Based on the evidence at the hearing, the Board concludes that the potential for sales of natural gas will be approximately equal to the TQM forecast up to 1990, but will be somewhat lower after that time. The later period relates rather to the expansion of the pipeline system than to its initial design. The use of natural gas for electric power generation could absorb surplus pipeline capacity during the market development period.

A great deal needs to be done by federal and provincial governments and regulatory agencies and by

transmission and distribution companies before gas can begin to flow to consumers in the Maritimes. The Applicant's schedule for delivery of gas to Nova Scotia in 1983 is, in the Board's view, unrealistic. If the attachment of natural gas markets were delayed for 12 months, the likely effect would be that the Board's forecast in the residential, commercial, and industrial sectors would remain at the same level but be delayed one year. The Board's forecast for potential thermal loads on an interim basis would be jeopardized because of the impact of such a delay on the economics of temporarily converting the generating plants to natural gas. Since these potential thermal loads are a relatively minor portion of the Board's forecast of sales, the Board does not view their possible loss as critical to its decision.

The Board finds that an adequate supply of Alberta gas exists to supply the markets to be served by the project, and while Sable Island gas may eventually be used to supply the need of the Maritimes, it is not possible at this time to rely on this potential source of supply for these markets.

The Board accepts TQM's design of the mainline, laterals, and sub-laterals, as well as the cost estimate and Canadian content of the project. The acceptance of the final design is, however, subject to confirmation that the pipe diameters selected are the appropriate ones, depending upon the results of studies relating to the possibility of storing gas in underground salt caverns.

The Board is satisfied with the general location of the proposed pipeline route. The Board finds that the environmental impact of constructing and operating the pipeline can be satisfactorily mitigated, providing the Applicant fulfills the undertakings identified at the hearing, and adheres to its construction plans within each spread.

Contracts are not yet in place for the supply of gas, for the transmission of gas, or for the sale of gas to distributors. The key feature of the contracting process will be the distributor contracts. The Board is confident that,

once the incentive measures contained in the NEP with respect to market development bonuses, conversion grants, and distributor viability, or some equivalent provisions, are implemented and distributors have been appointed, distributor contracts for volumes indicated in the initial years of the Board's demand forecast are likely to be signed. The Board believes that transmission contracts will follow once a tariff decision has been made based on the normal regulatory principles relating to financial integrity. Although executed supply contracts were not filed during the hearing, the availability of natural gas to supply the market was not in dispute. In any event, the Board will require all relevant contracts to be in place before permitting construction to begin.

The Applicant proposed to reduce the impact of high unit transportation costs in the initial years by deferring depreciation and return on equity, and by recommending that the government subsidize interest expense in the early years. These proposals would result in a netback to Alberta producers in the early years that is more acceptable to the Alberta Petroleum Marketing Commission and to CPA and IPAC. These proposals will be dealt with in future proceedings under Part IV of the NEB Act.

The Applicant proposed "project financing". The Board finds that the conclusion of contracts satisfactory to the Board, subject to the decision in the Part IV proceedings being satisfactory to the Applicant, will provide the basis for such financing.

The Board believes that the proposed pipeline extension should be examined in its broadest context. The principal consideration involved is a greater domestic use of available indigenous supplies of natural gas in conjunction with improved utilization of crude oil. The benefits sought are reduced reliance upon and lower expenditures for uncertain and expensive foreign oil measured against the costs for both gas transmission and distribution systems and probably for new oil refining equipment.

While the gas line facilities may be readily costed, it is less easy to ascribe a specific share of the likely investment in upgrading refinery facilities to the extension of domestic gas markets.

Somewhat similarly, the Board has not quantified the indisputable advantages of reduced reliance upon insecure supplies of foreign energy that the greater use of indigenous sources of natural gas would bring. In the Board's view, however, this factor is of crucial significance in any attempt to weigh the potential costs and benefits involved.

Notwithstanding these considerations, and in expectation that installation of heavy fuel oil upgrading facilities in eastern Canada would take place even in the absence of the TQM project, the Board has assessed the economic benefit of the TQM project, without attempting to attribute to it any portion of refining investment which its completion might entail, and leaving aside quantification of the advantage of its implied consequences for greater security of supply.

For purposes of its cost-benefit analysis the Board assumes that the gas which would otherwise be consumed in the Maritimes would be shut in until the year 2000. Using data provided at the hearing, the Board estimates that the net economic benefits of the pipeline over a 20-year period would be in the order of $1.5 billion. This assumes gas begins to flow in 1982, and that some of it is used temporarily for electric power generation. On this basis, the long-run real cost (excluding transfer payments, i.e., royalties and taxes) of Alberta gas delivered to the Maritimes would be less than 50 per cent of the cost of fuel oil derived from imported crude.

The Board, however, considers the estimate of net benefits of $1.5 billion to be unrealistically high given the somewhat optimistic assumptions underlying the estimates. For

instance, if the temporary use of gas for electric power generation did not occur, the benefits would be reduced to $1.3 billion. Second, this estimate of net benefits is based on a 1982 start-up and if the pipeline is delayed, as appears probable, a two-year delay would reduce the benefits to $1.1 billion. Third, the cost of construction might be greater than that placed in evidence in these proceedings and, as an example, a doubling of construction costs east of Alberta for transmission facilities, as well as for distribution systems, would reduce the benefits to $700 million from the $1.5 billion. If all three events were to occur on the scale indicated, then the benefits would only be about $200 million. The risks on the project appear to be mainly on the downside, from the upper limit of $1.5 billion.

A more difficult factor to assess is the potential impact of Sable Island gas which evidence suggested would be a high cost source. The Board is of the view that imponderables exist with respect to the volumes and timing of Sable Island gas such that an assessment of its effect on the net economic benefits of the TQM project is not possible at this time.

Another meaningful comparison is to measure the compensation payments (currently $24 a barrel) saved by not importing the oil against the subsidies required to ensure that gas penetrates the market. If gas were to flow in 1982, the compensation payments saved up to 1990 would amount to $2.4 billion, while the total subsidy for transmission facilities, market development bonuses, and conversion grants, would amount to about $1 billion. On the other hand, if the pipeline were to be delayed for two years, the compensation payments saved would be of roughly the same order as the natural gas subsidies.

The principal question remains the amount of added benefits from improved security of supply which should be ascribed to the project. While, on balance, the Board finds

that there is a reasonable prospect of a small net economic benefit, its decision to recommend certification of the TQM pipeline places more weight on the intangible benefits from increased security of supply than on the quantifiable net economic benefits. The risk of interruption in the supply of oil from the Middle East in the next few years makes the start of construction an urgent matter.

Under the existing pricing arrangement for the sale of natural gas and on the assumption that the price of natural gas will be the same in Halifax as in Montreal, the cost of transmission in the Maritimes will, in the absence of some form of subsidy, result in lower per unit netbacks to the Alberta producers than from other Canadian markets. This situation could be mitigated by the proposal that a significant federal financial contribution be made to the transmission facilities and by the levelling of the tariff resulting from TQM's proposal to defer depreciation and return on equity. The Board believes that the proposals would alleviate the burden that would otherwise have to be borne by the producers and lead to a more equitable sharing of the costs and risks of the project among the benefitting parties. The Board is satisfied that the certification of the pipeline is in the Canadian public interest taking into account the impacts on the various parties affected by the project.

Several other issues were raised during the hearing. Rerouting of the main line of the pipeline was proposed by intervenors for two areas in Quebec and also one in New Brunswick. The Board was not persuaded that any of the proposals put forward for rerouting were preferable to the route proposed by the Applicant.

Nova Scotia advocated designing and constructing the eastern portion of the line so that it would be able to accommodate Sable Island gas at a later date. There are, however, too many uncertainties with respect to the amount and

timing of availability of Sable Island gas for the Board to endorse this proposal at this time.

Additional laterals over and above those proposed by TQM, both in Quebec and Nova Scotia, were discussed in the hearing. The Board has determined that it is unwarranted at this time, based on the evidence adduced at the hearing, to cause the Applicant to build any of these proposed additional laterals.

CHAPTER 3

DECISION

Having considered all of the evidence, submissions and argument presented before it, the Board finds that with the exception of the compression facilities that were planned to be constructed after the operating year 1985-86, the facilities related to the application by Trans Québec & Maritimes Inc. for a proposed natural gas pipeline from Lévis/Lauzon in the Province of Quebec through New Brunswick to Halifax and Glace Bay in Nova Scotia, are and will be required by the present and future public convenience and necessity. The Board is prepared, therefore, subject to the approval of the Governor in Council, to issue to Trans Québec & Maritimes Pipeline Inc. a certificate of public convenience and necessity in respect of the above-described facilities, subject to the following terms and conditions:

1. The pipeline to be constructed pursuant to this Certificate shall be constructed and operated by Trans Québec & Maritimes Pipeline Inc.

2. The legal title in the pipeline to be constructed and operated pursuant to this Certificate shall be held by Trans Québec & Maritimes Pipeline Inc.

3. Trans Québec & Maritimes Pipeline Inc. shall, within thirty (30) days of the issuance of this Certificate, unless, upon application by Trans Québec & Maritimes Pipeline Inc. another time is fixed by the Board, file an executed copy of the General Partnership Agreement between Q & M Pipe Lines Ltd., TransCanada PipeLines Limited, and Trans Québec & Maritimes Pipeline Inc., filed as part of Exhibit 141 in the hearing set down by Order No. GH-1-81.

4.(1) Trans Québec & Maritimes Pipeline Inc. shall, at least ninety (90) days prior to the proposed date for the commencement of construction of the pipeline authorized by this Certificate, submit for the approval of the Board copies of:

(a) executed contracts for the sale of natural gas to those gas distributors who will distribute natural gas in market areas to be served by the pipeline facilities authorized by this Certificate;

(b) an executed contract or contracts for the transportation of natural gas to be sold to the distributors referred to in paragraph (a);

(c) executed contracts for the purchase by Trans Québec & Maritimes Pipeline Inc. of such volumes of natural gas required in relation to its obligations to distributors under the contracts referred to in paragraph (a);

(d) documents establishing that appropriate arrangements have been made for the financing of the pipeline facilities authorized by this Certificate, including the details of any financial contribution by the Government of Canada towards the capital cost or operating costs of the pipeline;

(e) its final estimate of the cost of the pipeline authorized by this Certificate, which estimate shall be based on the final design for the pipeline.

4.(2) Trans Québec & Maritimes Pipeline Inc. shall, at such time as it files the documents in compliance with subcondition 4.(1), serve a copy of the same on those parties of record in the hearing set down by Order No. GH-1-81 who have previously made a written request therefor.

4.(3) Unless otherwise ordered by the Board, any party of record who has been served with a copy of the documents in accordance with subcondition 4.(2) may, within thirty (30) days of service, file with the Board for its consideration in its approval process any comment with respect to such documents.

4.(4) Any party of record shall, at such time as it files a written document in accordance with subcondition 4.(3), serve a copy of the same on Trans Québec & Maritimes Pipeline Inc.

4.(5) Unless otherwise ordered by the Board, Trans Québec & Maritimes Pipeline Inc. shall, within fifteen (15) days of being served with documents in accordance with subcondition 4.(4), file with the Board any comment with respect to such documents.

5. Trans Québec & Maritimes Pipeline Inc. shall, at least ninety (90) days prior to the proposed date for the commencement of construction of the pipeline authorized by this Certificate, file with the Board for its approval:

(a) the final design for the pipeline including a description of any changes in the pipeline design from that submitted at the hearing set down by Order No. GH-1-81; and

(b) the procedures for project cost control in the construction of the pipeline authorized by this Certificate.

6. Trans Québec & Maritimes Pipeline Inc. shall, at such time as it files the final design referred to in subcondition 5(a), file with the Board a study of:

(a) the technical feasibility and the environmental impact of underground salt cavern storage facilities in New Brunswick based on the results of a confirmatory drilling program; and

(b) the economic advantages of providing peaking gas to distributors in the Provinces of Quebec, New Brunswick, and Nova Scotia by using underground storage facilities in the Province of New Brunswick as compared with other alternatives including underground storage in the Province of Ontario.

7. Trans Québec & Maritimes Pipeline Inc. shall, at least sixty (60) days prior to the proposed date for the commencement of construction of each segment of the pipeline authorized by this Certificate, file with the Board for its approval the following engineering data in respect of each such segment of the pipeline:

(a) a final stress analysis; and

(b) construction drawings, detailed materials specifications for line pipe and pipeline components, and technical data on compressor and metering facilities.

8. For the purpose of the engineering data referred to in subcondition 7(b), the pipe specification for the 457 mm diameter pipe shall require an all heat average notch toughness value at least equal to the arrest toughness value determined by the equation given in the Note to Clause 3.1.2.7 of the Canadian Standards Association Standard Z-184-M1979.

9. Trans Québec & Maritimes Pipeline Inc. shall cause the pipeline authorized by this Certificate to be constructed in accordance with the final design and engineering data approved by the Board pursuant to conditions 5 and 7, and shall not vary or cause or permit any variation to be made in the requirements of that final design and engineering data without the prior approval of the Board.

10. Trans Québec & Maritimes Pipeline Inc. shall, at such time as it files its plans, profiles, and books of reference for each segment of the pipeline authorized by this Certificate, file with the Board, for its approval in respect of each such segment, route maps of the same scale as those filed as Exhibit 22-7 in the hearing set down by Order No. GH-4-79, which maps shall identify any proposed deviations in excess of 300 metres from the route revised 31 May 1979 and identified in Exhibit 22-7.

11. Trans Québec & Maritimes Pipeline Inc. shall, at such time as it files its plans, profiles, and books of reference for each segment of the pipeline authorized by this Certificate, file with the Board in respect of each such segment

(a) line lists which shall include a statement of each landowner's requests made by any landowner respecting measures to be taken for the protection of farmlands and the environment in relation to such owner's lands;

(b) a list of all properties which require expropriation;

(c) a description of the location of any mine, mining claim, or borrow resource located within or immediately adjacent to the proposed right-of-way of the pipeline.

12. Trans Québec & Maritimes Pipeline Inc. shall, within ninety (90) days of the issuance of this Certificate, or on such later date as may be fixed by the Board, submit a schedule for the filing of the procedures manual and alignment sheets for the protection of farmlands and the environment in respect of each segment of the pipeline authorized by this Certificate.

13. Trans Québec & Maritimes Pipeline Inc. shall, at such times as specified in the schedule approved pursuant to condition 12, or on such other day as may be fixed by the Board, file for the approval of the Board a procedures manual and alignment sheets in respect of each segment of the pipeline authorized by this Certificate, setting out the site-specific mitigative measures and other plans and procedures to minimize the impact of the construction of the pipeline upon farmlands and the environment, which measures, plans, and procedures shall give effect to the results of the studies identified in:

(a) item 4 of the National Energy Board information request filed as Exhibit 23 of the hearing set down by Order No. GH-1-81; and

(b) volumes 6A and 6B of the Q & M Pipe Lines Ltd. application, which volumes were filed as part of Exhibit 158 in the hearing set down by Order No. GH-1-81.

14. Trans Québec & Maritimes Pipeline Inc. shall not, without the prior approval of the Board, make any variation in, or cause or permit any variation to be made in the measures, plans, and procedures for the protection of farmlands and the environment approved by the Board pursuant to condition 13.

15. Trans Québec & Maritimes Pipeline Inc. shall, unless otherwise authorized by the Board, implement or cause to be implemented all the policies, practices, and procedures for the protection of farmlands and the environment as set out in its application or as otherwise undertaken by Trans Québec & Maritimes Pipeline Inc. in the hearing set down by Order No. GH-1-81.

16. Trans Québec & Maritimes Pipeline Inc. shall, at such time as it submits its pressure testing program to the Board pursuant to Part III of the Gas Pipeline Regulations, file with the Board for its approval:

(a) the location of water withdrawal sites for testing purposes for those streams or other water courses where water removal may result in downstream water shortages or any adverse environmental effects;

(b) the location of alternative water sources which may be required in the event of water shortages; and

(c) the specific plans and procedures to be implemented to minimize any adverse environmental impact resulting from the withdrawal of water from or the discharge of water into any stream or other water course.

17. Trans Québec & Maritimes Pipeline Inc. shall, prior to applying for leave to open for any segment of the pipeline facilities authorized by this Certificate, file with the Board for its approval:

(a) its specifications for the operation, maintenance, repair, and abandonment of its pipeline as established pursuant to section 65 of the Gas Pipeline Regulations;

(b) a detailed program for the monitoring of the condition of its right-of-way during the operation of the pipeline authorized by this

Certificate, having particular regard to those parts of the right-of-way susceptible to adverse environmental impact and including a comparison of crop productivity on the right-of-way in relation to that on adjacent farmlands.

18. Trans Québec & Maritimes Pipeline Inc. shall, within six (6) months of obtaining leave to open for each segment of the pipeline authorized by this Certificate, submit for the approval of the Board a report in respect of each such segment of the pipeline assessing the effectiveness of:

(a) the measures, plans, and procedures approved by the Board pursuant to condition 13; and

(b) any variations in those measures, plans, and procedures approved by the Board pursuant to condition 14.

19. Trans Québec & Maritimes Pipeline Inc., shall, prior to the 1st day of November in each of the two (2) years immediately following the granting of leave to open for each segment of the pipeline authorized by this Certificate, file a report in respect of each such segment setting out the results of the monitoring program established pursuant to subcondition 17(b), together with any actions taken or measures implemented to prevent or mitigate any long-term effects of the pipeline upon farmlands and the environment.

20. Trans Québec & Maritimes Pipeline Inc., shall, within twelve (12) months of being granted leave to open for the final section of the pipeline authorized by this Certificate, file with the Board a report setting out for each category of cost enumerated in Table 6-4 of the Reasons for Decision of July 1981, the percentage of Canadian content achieved in comparison with the estimates given in the said Table and the reasons for any variations from those estimates.

21. Trans Québec & Maritimes Pipeline Inc. shall, in maintaining the records and books of account of TQM Pipeline Partnership, follow the accounting instructions set out in the Gas Pipeline Uniform Accounting Regulations as if these regulations otherwise applied to the Partnership.

22. Trans Québec & Maritimes Pipeline Inc. shall cause the construction and installation of the pipeline authorized by this Certificate to be completed on or before the 1st day of December, 1986, unless, upon application by Trans Québec & Maritimes Pipeline Inc., a later day is fixed by the Board.

* * * * * *

All of which is respectfully submitted.

C. Geoffrey Edge

C. Geoffrey Edge
Presiding Member

J. Farmer

J. Farmer
Member

A.B. Gilmour

A.B. Gilmour
Member

CHAPTER 4
NATURAL GAS DEMAND

4.1 Introduction

The Applicant and intervenors identified various major issues affecting the potential penetration of natural gas in energy markets in New Brunswick and Nova Scotia. This chapter reviews these issues and summarizes forecasts of natural gas demand in the Provinces of New Brunswick and Nova Scotia.

4.2 Major Issues

4.2.1 National Energy Program

Evidence of the Applicant. TQM stated that some elements of the National Energy Program would play an important role in the penetration of natural gas in New Brunswick and Nova Scotia. These included the extension of the eastern rate zone to Halifax, the proposed price advantage of gas over oil, the NEP conversion grants, and the establishment of a fund to finance the conversion of federal government buildings and facilities to natural gas use. TQM's forecast was also based on the statement in the NEP that heavy fuel oil would not be allowed to compete to the disadvantage of natural gas.

Another element of the NEP that was addressed by the Applicant was the market development bonus, for which TQM identified possible uses. For example, this could be used to defray part of the capital costs of the project facilities, to subsidize burner-tip prices of gas during the early years of the project, to defray distributor deficiencies, to fund the equivalent of a development rate, to reduce load factor penalties, to finance expansion of the distribution system, or to provide for some additional decreases in customer billings.

Views of the Intervenors. Nova Scotia stated that a number of elements of the NEP would accelerate the penetration

of natural gas into Nova Scotia markets. The extension of the eastern zone to Halifax and the pricing régime of natural gas vis-à-vis oil were important elements affecting the price of gas to consumers. Funds from the market development bonus program were seen as serving the dual purposes of financing construction of the distribution system and extensions to additional communities. It was anticipated that the conversion grant program would accelerate the normal furnace replacement process, and hence the penetration of gas into residential markets. Reliance was also placed upon statements in the NEP to the effect that measures would be undertaken to prevent undue competition from heavy fuel oil if sales of natural gas were blocked. Without such intervention, it was stated, the displacement of heavy fuel oil would be much more difficult.

ICG Scotia stated that two elements of the NEP would particularly affect the penetration of gas in Nova Scotia. First, steps must be taken to ensure that gas displaced heavy fuel oil. If this did not happen, ICG Scotia's forecast of gas demand in the industrial sector would not be achieved. Second, to meet its forecast, ICG Scotia would require about $90 million in subsidies for the basic distribution system. For extension of the system through the Annapolis Valley another $10 million would be required. Other elements of the NEP, while important, did not materially affect ICG Scotia's demand forecast because it was assumed that incentives in some form would be required in any event.

New Brunswick stated that provisions of the NEP would not materially affect the outlook for natural gas demand in the Province. This was so because the incentives provided by the NEP, while significant, were not markedly greater than those assumed by Q & M at the time of the previous application. New Brunswick noted that provisions of the NEP that might affect the outlook for natural gas sales were in the form of general statements only.

New Brunswick stated that, while some specific provisions of the NEP would be advantageous to the Province, the NEP appeared to rule out the use of natural gas for thermal generation. For the purpose of its forecast New Brunswick did rely on the NEP statements concerning steps to be taken if natural gas met undue competition from heavy fuel oil. Without such steps, industrial sales of natural gas, a major portion of the potential gas market, would not reach the volumes forecast by the Province. New Brunswick stated that the market development bonus could be used in part to meet distributor deficiencies and in part to finance system extensions, while the transmission extension fund could be used in part to finance system extensions to areas additional to those proposed by TQM.

Items from the NEP which were specifically mentioned by ICG Brunswick as affecting natural gas demand in New Brunswick included the conversion grant program, the upgrading of heavy fuel oil, and the market development bonus. The market development bonus was seen as a source of assistance in constructing the basic distribution system, while the conversion grant program would aid market penetration in the residential and small commercial sectors. ICG Brunswick also expressed concern about competition between heavy fuel oil and natural gas. It stated that to achieve its forecast there would have to be some programs in place to reduce quantities of heavy fuel oil available in the Maritime provinces.

Views of the Board. The Board agrees that certain provisions of the NEP would affect the demand for natural gas in New Brunswick and Nova Scotia. The price incentives afforded by the extension of the eastern zone and the establishment of the NEP relationship between oil and gas prices would aid market penetration in all sectors, while the NEP conversion grant program would encourage conversions from oil to natural gas by residential and small commercial customers.

4.2.2 Disposal of Heavy Fuel Oil

Evidence of the Applicant. The Applicant assumed that heavy fuel oil would not compete to the disadvantage of natural gas. On the basis of responses given by the Applicant when cross-examined by intervenors, it is apparent that TQM believed that heavy fuel oil would not stand in the way of natural gas penetration, because:

(1) heavy fuel oil prices would maintain a constant relationship with crude oil prices and, therefore, heavy fuel oil prices would not be reduced to compete with gas;

(2) heavy fuel oil displaced as a result of the extension of natural gas service by TQM could be exported;

(3) the oil import compensation program could be altered to prevent the import of heavy fuel oil;

(4) a number of refinery upgrading projects have been announced, and Petro-Canada, together with Montreal refiners and SOQUIP, was considering a central upgrader in Montreal which, if constructed, would absorb a significant volume of heavy fuel oil;

(5) the federal government through the NEP has adopted as a policy goal the upgrading of refineries to reduce the production of heavy fuel oil and has indicated that, if needed, measures would be put in place to ensure that upgrading occurs.

Views of the Intervenors. In its submission, APMC noted that the effect of the oil import compensation program in 1980 was such as to encourage imports of heavy fuel oil at prices well below those of crude oil. The Commission did not believe that any substantial measures had been proposed for the Maritimes which would eliminate the surplus of residual fuel. In these circumstances, it felt that unless refineries were upgraded the surplus of heavy fuel oil could be sold at prices to clear the market. Consequently, the Commission

judged that the Applicant's natural gas demand estimates in the industrial sector might be optimistic. Moreover, if refineries were not upgraded, the extension of gas to New Brunswick and Nova Scotia might not result in an equivalent displacement of crude oil because the same volume of feedstock as is currently imported could be needed to satisfy the demand for transportation fuels.

New Brunswick referred to the Applicant's assumption of the removal of heavy fuel oil from competition with natural gas in the industrial market and noted that no details were provided as to how and when this would be achieved, what this would cost, and who would bear the costs. The Province believed that this assumption was critical to the TQM proposal.

Views of the Board. There exists currently a surplus of heavy fuel oil in eastern Canada and there appear to be a number of factors that, in the short term, are likely to result in an increase in the surplus. These include the trend to heavier crude oil imports, a declining demand for heavy fuel oil, and the possibility of relatively inexpensive residual oil being imported into Canada. The success of natural gas penetration in New Brunswick and Nova Scotia, and hence the TQM project, would depend to a large extent on natural gas displacing heavy fuel oil in industrial markets. In this regard, the Board cannot accept the assumption of TQM that residual oil prices would necessarily maintain a constant relationship with crude oil prices. With a growing surplus of heavy fuel oil expected in the near term, the Board believes that there would be a considerable risk of residual oil prices being reduced to compete with natural gas and that, therefore, measures would have to be adopted to ensure that the surplus was disposed of. The Board's forecast of natural gas demand, based on the evidence in these proceedings, assumes that such measures will be taken.

The Board believes that the major challenge for refiners in the early to mid-1980's is to reduce the production of heavy fuel oil. The Board notes that some upgrading projects at individual refineries in Ontario and Quebec have been announced and that studies are underway on the possibility of a central heavy fuel oil upgrader in Montreal. Such a project, if constructed, would go a long way toward reducing any large surplus of heavy fuel oil in eastern Canada.

The Board notes that the federal government, through the NEP, has established as a major element of energy policy an objective seeking the modification of existing refineries to reduce significantly the production of heavy fuel oil, and suggested that if heavy fuel oil were blocking sales of non-oil fuels, measures would be adopted to ensure that upgrading occurred. The Board is aware of some actions that could be taken and the government has presumably identified a number of potential options in the course of developing its policy. In any case, the Board believes that it would be essential for the government to announce as soon as possible the specific measures that it would be prepared to take to ensure that necessary upgrading occurs.

The Board is of the opinion that penetration of natural gas into Maritimes markets would be facilitated by minimizing the possibility of heavy fuel oil being imported at prices that could compete with gas. For this purpose, the Board recommends that the government review the oil import compensation program, with a view to implementing changes which would eliminate unnecessary imports of heavy fuel oil and, perhaps, reduce the imports of heavy crude oils yielding a high proportion of residual oil.

The Board is aware that the government has the ability to reduce the consumption in the Maritimes of fuel oil from imported crude oil, and that it is the government's policy to do this.

4.2.3 Pricing and Conversion Cost Payment Assumptions

Evidence of the Applicant. TQM assumed that city-gate prices of natural gas would follow the pricing scenario set out in the National Energy Program. Burner-tip prices of natural gas were forecast by adding estimated distribution margins to the city-gate price, with allowance for some additional subsidies in the early years of the project. Natural gas was assumed to have a price advantage compared with TQM's forecast burner-tip prices of oil products, varying for each sector from year to year. In the early years of gas service, natural gas was assumed to have a price advantage in the range of 10 to 15 per cent in all market sectors. For the residential and commercial sectors, this increased over time to a range of 15 to 20 per cent by the year 2000, while for interruptible industrial gas sales, the price advantage was assumed to decline to about 1 per cent by 2000.

TQM assumed that the NEP conversion grants would be available for a period of at least 10 years. The taxable grant covering 50 per cent of conversion costs to a maximum of $800 was assumed to apply for conversions from oil to gas by residential and small commercial customers.

Views of the Intervenors. For the purpose of its forecast, Nova Scotia assumed that the cost to the customer of using natural gas after accounting for conversion costs would be lower than the comparable cost of oil or electricity. Residential and business customers were assumed to be eligible for the NEP conversion grants. Both ICG Scotia and ICG Brunswick assumed that natural gas would have a 10 per cent price advantage over alternative fuels. The NEP conversion grant program was to apply in the residential and small commercial sectors, with additional funds being provided so that residential and small commercial customers would pay no more than 25 per cent of total conversion costs. New Brunswick assumed that natural gas would be the economic choice over fuel oil after amortization of conversion costs.

It was also stated, however, that electricity might become more attractive than gas for space heating purposes. New Brunswick assumed that residential and small commercial customers would be eligible for the NEP conversion grants from oil to natural gas, but also stated that these customers might be eligible for conversion grants from oil to electricity.

Views of the Board. In preparing its forecast of natural gas demand in New Brunswick and Nova Scotia, the Board has adopted the pricing and conversion cost payment assumptions presented in the evidence of the Applicant. In the Board's view, however, the incentives contained in the NEP, when considered in conjunction with their income tax implications, may not be sufficient to ensure rapid penetration of the residential and small commercial markets. The Board does note that with additional incentives, such as the 75 per cent payment of conversion costs in the residential and small commercial sectors assumed by ICG Brunswick and ICG Scotia, penetration of the residential and commercial markets could proceed more quickly than indicated in the Board's forecast.

4.2.4 Speed of Penetration

Evidence of the Applicant. TQM assumed that distribution organizations would be in place and capable of meeting the TQM construction schedule and market forecast and that the distribution systems would be developed in a steady and orderly manner over the forecast period. The Applicant stated that apart from possible regulatory lags affecting the proposed transmission facilities, the establishment of a distributor could be on the "critical path" to maintaining the scheduled delivery date for gas to New Brunswick by November 1982.

TQM advised that to achieve the proposed schedule, certification of its proposed facilities would have to be received by June 1981 and shortly thereafter the provinces

would have to award the franchise contracts to the distributors. Given these approvals, it was the Applicant's belief that the distributor would be able to obtain all necessary provincial regulatory approvals, develop and put in place the distribution infrastructure, and within six months of gaining franchise rights the distributor would have signed sales contracts with some of its large volume industrial customers. The Applicant felt that any distributor appointed would concentrate primarily on contracting with large volume industrial users because these customers could be prepared for gas service in advance, and they also represent the largest potential gas market, and as such would serve as the basis for contracted purchases from TQM.

TQM did point out factors beyond the control of the distributor that could delay deliveries of gas by TQM. These included the enactment of certain provisions of the NEP in regard to pricing and distributor assistance as well as provincial regulatory approvals. Although these factors would not directly cause TQM to revise its construction schedule, the fact that they might not allow the distributor to proceed could require TQM to delay construction because there would have to be a distributor in place and capable of taking deliveries when gas was made available.

Views of the Intervenors. New Brunswick stated in its intervention that it supported the early construction of the pipeline and gas distribution system and it would give timely consideration to the method of gas distribution and the selection of distributors.

The Province advised that a Cabinet Committee on Natural Gas Distribution was studying the matter. New Brunswick was unable to provide a complete schedule of the various regulatory approvals and the corresponding timetable that a distributor would have to follow, nor was it able to provide the Board with assurance that the necessary regulatory controls and the enabling legislation would be in place to

meet the TQM schedule for gas deliveries by November 1982. New Brunswick did state, however, that its objective was to have a distribution system constructed and ready to accept gas in accordance with the TQM timetable.

ICG Brunswick testified that it intended to apply for natural gas franchise rights in the Province of New Brunswick. ICG Brunswick estimated that from the time it received a franchise award it would require approximately nine months to go through the steps necessary to set up a distribution organization. When an estimated construction period of some seven months was also accounted for, ICG Brunswick felt that it could be ready by November 1982 to receive gas from TQM if the distributorship were awarded promptly, and absent further regulatory lag.

Nova Scotia advised the Board that it was in the process of reviewing two applications for distribution franchise rights and it expected that a decision would be rendered by June 1981. Therefore, considering the proposed November 1983 delivery date for gas to Nova Scotia by TQM, it did not anticipate any difficulty in having distribution facilities ready and in place to market the gas.

ICG Scotia informed the Board that, if it was awarded the franchise rights in Nova Scotia, it would require approximately nine months in order to establish a distribution organization capable of starting construction of a distribution system. It felt that given the lead time available to it in Nova Scotia, there probably would be no difficulty in being ready to accept gas deliveries by November 1983.

Views of the Board. The Board agrees that the state of readiness of the distributor is the key to achieving the proposed delivery schedule for gas to New Brunswick and Nova Scotia. The Board is also aware that some of the impediments that might arise are likely to be beyond the control of the

distributor and would be due to delay in receiving regulatory approvals at either the provincial or municipal level. The Board has very real concerns with respect to the ability of New Brunswick to put in place the necessary regulatory procedures governing a distributor's operation in time to meet TQM's proposed schedule. Evidence provided by New Brunswick was not clear as to the Province's state of preparedness and its ability to implement sufficiently quickly the necessary regulatory infrastructure. ICG Brunswick, although optimistic, did emphasize that its ability to meet the TQM delivery date depended almost entirely on how the Province was able to meet its obligations. No evidence was provided on the ability of municipal bodies to accommodate the setting up of a new utility.

On the basis of the evidence before it, the Board is of the opinion that a distributor would not be ready to serve markets in New Brunswick for a period of six months to one year after the November 1982 date put forward by the Applicant. Despite these difficulties, the Board has adopted TQM's timetable for the purposes of its demand forecast.

The Board considers there is adequate time for the necessary provincial regulatory controls and procedures to be implemented and a distributor approved and ready to serve Nova Scotia markets by November 1983.

4.2.5 Development Rate

Evidence of the Applicant. TQM had initially proposed that a development rate be part of its sales contracts with the distributors. The development rate proposed would have allowed a distributor to purchase gas for the first three years at a cost equivalent to the unit rate for CD Service at 100 per cent load factor, regardless of the distributor's actual load factors.

During the course of the hearing, TQM withdrew its development rate proposal because it felt that the cost of

this type of service would fall on Alberta producers under the present pricing regime, but it recognized the importance a development rate could have in aiding market penetration and suggested that a proxy for a development rate be implemented with the cost being met from the market development bonus proposed in the NEP.

Views of the Intervenors. ICG Brunswick indicated that it would discuss with TQM the possibility of including a development rate as part of its contract terms. Its opinion was that a development rate would be of greater benefit than a market development bonus. ICG Brunswick stated that without a development rate its demand forecast would be lower.

ICG Scotia argued that it would prefer to have a development rate as part of its sales contract.

Views of the Board. Matters relating to development rates and prices will be dealt with in other proceedings before the Board. It is sufficient to record at this time that in the Board's view development prices or something similar thereto would be essential to the development of the TQM market.

4.3 Comparison of Forecasts

4.3.1 Overview

Evidence of the Applicant. TQM's forecast of natural gas demand included 19 communities in New Brunswick and 12 in Nova Scotia, with gas service begining in 1982 in New Brunswick and 1983 in Nova Scotia. The forecast excluded natural gas used for the thermal generation of electricity because the NEP appeared to rule out that possibility.

Demand in New Brunswick and Nova Scotia combined was forecast to reach about 31 PJ by 1985, 73 PJ by 1990, and 103 PJ in the year 2000. Details of this forecast by market sector are provided in Table 4-2, while Figure 4-1 illustrates the combined total.

Views of the Intervenors. Forecasts for the Province of Nova Scotia were provided by Nova Scotia and ICG Scotia, while New Brunswick and ICG Brunswick provided forecasts for the Province of New Brunswick. These forecasts are compared with those of the Applicant and the Board in Table 4-2 for all market sectors.

Nova Scotia provided three forecasts: a base case forecast comprising the same communities included in the TQM projection; a forecast of requirements for a lateral along the South Shore of the Province; and, a forecast of requirements for a lateral through the Annapolis Valley. These forecasts included projections of gas sales for thermal generation. For the base case forecast, including thermal generation requirements, Nova Scotia projected sales of about 37 PJ in 1985, 35 PJ in 1990, and 46 PJ in 2000 for all market sectors within the province.

ICG Scotia's and ICG Brunswick's forecasts covered ten years and included a number of communities additional to those in the TQM forecast as well as projections for thermal generation. ICG Scotia's forecast, including thermal generation requirements, was about 29 PJ in 1985 and 31 PJ in 1990. ICG Brunswick's forecast, including thermal generation requirements, was 57 PJ in 1985 and 63 PJ in 1990.

The forecast prepared by New Brunswick included a number of communities additional to those in the TQM forecast, and included projections of natural gas requirements for thermal generation. New Brunswick forecast about 39 PJ in 1985 and 36 PJ in 1990, the decline being due to a reduction in the forecast of gas to be used for thermal generation.

Views of the Board. Based on the evidence adduced by various parties in the proceedings, the Board prepared its own forecast of natural gas demand which included the same communities in New Brunswick and Nova Scotia as comprised the TQM service area. This forecast includes natural gas requirements for thermal generation based upon available

pipeline capacity. Natural gas demand in New Brunswick and Nova Scotia combined are forecast to reach 59.7 PJ by 1985, 64.1 PJ by 1990, and 86.0 PJ by 2000. Significant variations between the Board's and TQM's forecast are discussed in the appropriate sections. Excluding thermal generation, the Board's forecast for the two provinces is 1 per cent higher than TQM's in 1985, 13 per cent lower in 1990, and 17 per cent lower in 2000.

4.3.2 Residential Sector

Evidence of the Applicant. TQM's forecast of residential demand is shown in Table 4-2 in comparison with those of intervenors and the Board. For New Brunswick and Nova Scotia, TQM forecast natural gas demand increasing to 7.9 PJ in 1985, to 20.5 PJ in 1990, and to 27.2 PJ in 2000.

In forecasting natural gas demand in the residential sector, TQM examined the economic benefits accruing to customers converting from oil to natural gas. The Applicant's assumed conversion rates of existing dwellings and capture rates of new dwellings were based on this analysis.

Views of the Intervenors. Nova Scotia forecast residential demand to be 8.5 PJ in 1985, 11.7 PJ in 1990, and 16.1 PJ in 2000. Nova Scotia assumed a much more rapid penetration of the conversion market than did ICG Scotia or TQM, and also assumed more rapid population growth.

ICG Scotia forecast residential natural gas demand to be 2.7 PJ in 1985 and 8.4 PJ in 1990. This forecast was lower than that of Nova Scotia because of a lower estimate of the number of households in the proposed natural gas service areas.

New Brunswick's forecast of natural gas demand in the residential sector was 3.6 PJ in 1985 and 5.8 PJ in 1990. This forecast was lower than TQM's forecast for New Brunswick because the Province assumed a much more gradual build-up of the conversion market and a lower average use per customer

than did TQM. New Brunswick questioned whether the NEP conversion grants provided sufficient incentives, particularly when the grants were evaluated on an after-tax basis.

ICG Brunswick forecast natural gas demand in the residential sector to be 3.4 PJ in 1985 and 6.6 PJ in 1990. This forecast was lower than that of TQM because of a lower estimate of the number of households.

Views of the Board. As a result of its assessment of the evidence, the Board forecasts natural gas demand in the residential sectors of New Brunswick and Nova Scotia to be 5.7 PJ in 1985, 14.6 PJ in 1990 and 21.2 PJ in 2000. This forecast is lower than TQM's for two major reasons. First, the Board assumes a much more gradual build-up of the conversion market than does TQM. In the Board's view, the economic incentives assumed by the Applicant are not sufficient to encourage widespread early retirement or conversion of furnaces, but rather, are sufficient only for natural gas to capture most of the normal oil furnace replacement market. Second, the Board assumes a higher average use per customer initially than TQM, but declining over time because of more widespread use of higher efficiency furnaces, and, to a lesser extent, other conservation measures such as retrofitting. On balance over the forecast period, the Board assumes a lower average use per customer than does TQM.

4.3.3 Commercial Sector

Evidence of the Applicant. TQM's forecast of natural gas demand in the commercial sectors of New Brunswick and Nova Scotia is summarized in Table 4-2. Demand for natural gas in the two provinces was forecast to increase to 5.4 PJ in 1985, to 14.1 PJ in 1990, and to 18.7 PJ in the year 2000.

The Applicant estimated the number of commercial customers to be one-tenth of the number of residential

customers, implying conversion rates for existing establishments and capture rates for new establishments as assumed for the residential sector.

Views of the Intervenors. Nova Scotia estimated the number of commercial establishments in the proposed service areas independently and projected these on the basis of an assumed growth rate. Nova Scotia forecast commercial sector demand to be 3.1 PJ in 1985, 7.7 PJ in 1990, and 15.8 PJ in the year 2000. Nova Scotia's forecast was considerably higher than TQM's forecast for Nova Scotia in the year 2000. This variance was principally due to different estimates of the number of customers.

ICG Scotia conducted a building-count survey to establish the number of commercial establishments in the proposed service areas. An average use was assumed for small commercial establishments, while large commercial and institutional establishments were contacted directly concerning their annual requirements. ICG Scotia forecast commercial sector demand in Nova Scotia to be 9.1 PJ in 1985 and 14.6 PJ in 1990.

New Brunswick estimated that 80 per cent of all commercial activity in the Province is included in the proposed gas service areas, and that 90 per cent of the heavy fuel oil, light fuel oil, and propane used in the commercial sector would have been displaced by natural gas by 1991. New Brunswick forecast commercial sector demand to be 5.6 PJ in 1985 and 7.1 PJ in 1990.

ICG Brunswick followed a methodology similar to that used by ICG Scotia. ICG Brunswick forecast commercial sector demand in New Brunswick to be 8.8 PJ in 1985 and 12.0 PJ in 1990.

Views of the Board. As part of its assessment of the evidence, the Board estimated the number of potential

commercial customers, as did TQM, by assuming one commercial for every ten residential customers. The Board forecasts commercial sector demand in New Brunswick and Nova Scotia to be 3.9 PJ in 1985, 10.5 PJ in 1990, and 17.3 PJ in 2000. This forecast is lower than TQM's forecast throughout the period, but particularly in the earlier years because, as discussed in the residential sector, the Board assumes a much more gradual penetration of the conversion market than does TQM.

4.3.4 Industrial Sector

Evidence of the Applicant. TQM's forecast of natural gas demand in the industrial sectors of New Brunswick and Nova Scotia is shown in Table 4-2. Gas demand for New Brunswick and Nova Scotia was forecast to increase to 17.4 PJ by 1985, to 38.8 PJ by 1990, and to 57.1 PJ by the year 2000.

Potential industrial volumes in the proposed natural gas service areas were estimated by TQM to be 21.5 PJ in Nova Scotia and 43.8 PJ in New Brunswick in 1980. These potential volumes represent total industrial energy consumption exclusive only of electricity, and embody the assumptions that no major industrial customer would be excluded in New Brunswick and that about 80 per cent of industrial usage in Nova Scotia would be in the natural gas service areas. During cross-examination, TQM agreed that, in making its forecast, there had been a misallocation of potential industrial load between the provinces.

Hog fuel and pulping liquor were seen as important factors restraining the penetration of natural gas in the pulp and paper industries of the two provinces, particularly New Brunswick. TQM stated that it had accounted for the use of hog fuel and pulping liquor by assuming a maximum penetration rate of 60 per cent in industrial markets.

Views of the Intervenors. In its base case forecast, Nova Scotia predicted industrial sales of natural gas to be

9.3 PJ in 1985, 10.2 PJ in 1990, and 12.4 PJ in the year 2000. Nova Scotia's forecast was lower than other forecasts of industrial demand in the province principally because Nova Scotia assumed that the bulk of the heavy fuel oil currently used to generate steam would convert to coal rather than to natural gas.

To estimate the potential use of natural gas in the industrial sector, Nova Scotia contacted a number of large industries located in the proposed service areas to determine their requirements and the likelihood of their converting to gas. A number of industries were then assumed to convert to natural gas. Natural gas demand was reduced to account for an expected increase in the use of hog fuel. Based on firm industry plans to increase use of hog fuel, Nova Scotia expected that heavy fuel oil requirements in the pulp and paper industry of the province will be reduced 50 per cent by the end of 1984.

ICG Scotia forecast industrial demand in Nova Scotia to be 8.4 PJ in 1985, remaining constant at that level until 1992, the last year of the forecast. Industrial demand was estimated by contacting potential large volume industrial customers directly, but it was not stated which customers were assumed to convert to natural gas. ICG Scotia's forecast of industrial demand was reduced to account for the plans of the two pulp and paper mills in Nova Scotia to convert to the use of hog fuel.

New Brunswick estimated that 80 per cent of total industrial energy usage in the province was in the proposed natural gas service areas. Based on this, New Brunswick forecast natural gas demand in the industrial sector to be 18.5 PJ in 1985 and 20.6 PJ in 1990. The Province argued that the forecasts of TQM and ICG Brunswick were higher than New Brunswick's forecast because the other forecasts did not adequately account for increased use of hog fuel and pulping liquor in the pulp and paper industry. New Brunswick expected

the fossil fuel requirements of pulp and paper mills to be reduced by 10.4 PJ by 1985 because of increased use of hog fuel and pulping liquor.

ICG Brunswick estimated industrial demand by contacting potential large volume industrial customers directly. Based on this, industrial demand was forecast to be 31.7 PJ in 1985 and 31.8 PJ in 1990. However, ICG Brunswick subsequently reduced its forecast for 1991 from 31.9 PJ to 28.3 PJ and indicated that this reduced volume also included 2.6 PJ of demand classified as institutional, which other submittors included in the commercial sector. ICG Brunswick reduced fossil fuel requirements in the pulp and paper industry by 25 per cent by 1985 to account for expected increases in the use of hog fuel and pulping liquor.

Views of the Board. As part of its assessment of potential industrial volumes the Board reviewed two sources of evidence presented at the hearing. First, provincial heavy fuel oil volumes were allocated to the proposed service areas on the basis of sub-provincial data on the cost of fuel and electricity. Second, the volumes derived in this manner were checked against survey information provided by the Applicant. The volumes arrived at using these two methods were similar in magnitude. The Board's estimate of potential, substitutable fuel was reduced in both provinces to account for an expected 25 per cent increase in the use of hog fuel and pulping liquor by 1985.

The Board forecast industrial demand in New Brunswick and Nova Scotia to be 21.6 PJ in 1985, 39 PJ in 1990, and 47.5 PJ in 2000. The Board's forecast is higher than TQM's in the early years of gas service because the Board assumes, as did Nova Scotia, New Brunswick, ICG Scotia, and ICG Brunswick, a much more rapid build-up of the market than did TQM. In 1990, the Board's forecast for New Brunswick is lower than that of ICG Brunswick, but not significantly so if

ICG Brunswick's downward revision is taken into account and given that ICG Brunswick's industrial sector forecast also included some commercial sector usage. The Board's forecast for New Brunswick is considerably lower than TQM's forecast in the year 2000, but the Applicant recognized that it might have overstated the size of the potential market in New Brunswick. The Board's forecast for Nova Scotia is considerably higher than Nova Scotia's forecast in 2000, principally because Nova Scotia assumed that most of the steam currently generated using oil would be generated by coal by 1987, while the Board assumes that natural gas would penetrate the steam generation market to some extent.

4.3.5 Thermal Generation Potential.

Evidence of the Applicant. TQM stated that talks with utilities in New Brunswick and Nova Scotia indicated a potential for gas sales to replace oil for thermal generation for an interim period while generating plants were converted to coal. However, no such demand was included in TQM's forecast.

TQM understood that the NEP precluded the use of natural gas for thermal generation on a permanent basis but believed that gas could be used on an interim basis while a supply of local coal was developed and stations converted to coal.

TQM considered that the supply of gas to thermal plants would be of great help in reducing the unit cost of gas service, particularly in distribution, during the initial market build-up.

Views of the Intervenors. ICG Brunswick estimated a constant total thermal load of 12.47 PJ as shown in Table 4-1. It assumed this quantity of natural gas would be available as consumers required it.

ICG Scotia included only the thermal load for Tufts Cove until 1986 at which time the plant would be converted to coal. All three units were assumed to be converted to natural gas from oil but the forecast volume of gas was only about two-thirds of the amount needed if all fuel oil were replaced. Some oil would be required in the winter peak period. This estimated thermal load is shown in Table 4-1.

New Brunswick stated that NBEPC believed the Coleson Cove plant (1000 MW) and Courtenay Bay Unit #2 (13 MW) should have natural gas burning capability. Courtenay Bay #2 is a co-generation unit with its steam and electricity output dedicated to MacMillan Rothesay pulp and paper mill. The use of gas in the unit might encourage the conversion of other similar installations to gas.

New Brunswick stated that natural gas use at Coleson Cove in the short term and Courtenay Bay over a longer period would enhance the economic viability of the TQM project by increasing throughput levels as follows:

	1983	1984	1985
TQM projected sales (PJ)	6.5	17.5	30.8
Projected power plant usage (1)(PJ)	12.2	13.0	11.0
Capacity factor (2)			
- without power plant usage (%)	8.5	22.7	39.8
- with power plant usage (%)	24.3	39.4	54.4

NOTES: (1) - Projected gas usage assuming gas is used only in the most heavily loaded unit at Coleson Cove.

(2) - Capacity factor defined as annual sales divided by tenth year sales projected by TQM.

According to New Brunswick the economic viability of the TQM project could be further enhanced by burning even modest quantities of gas at Coleson Cove in off-peak periods after 1985.

The Province stated conversion costs for Coleson Cove and Courtenay Bay #2 would be relatively modest; therefore, payback of the conversion costs would be achieved

in a short time. An estimate of the potential thermal load is given in Table 4-1. For the estimate, it was assumed that the natural gas system would be capable of meeting the peak requirements of only one unit at Coleson Cove at a time. The estimated gas requirements were based on the assumption that Coleson Cove would be converted back to heavy fuel oil in 1986 as the NEP would not permit continued operation on gas. NBEPC was, however, considering other alternatives including conversion to coal or Venezuelan crude.

New Brunswick stated that NBEPC would like to burn local coal in Coleson Cove, but provincial coal reserves are not adequate to maintain the plant and the quality of the coal is not environmentally acceptable. Possible sources of coal were western Canada or the eastern United States.

New Brunswick testified it was possible to have Coleson Cove converted to coal by 1986 as conversion would take 2 to 2½ years after a decision was made.

They also testified that there had been some indication that the federal government would agree to the burning of gas in the short term.

Nova Scotia testified that the only plant considered for conversion from oil to gas was Tufts Cove at Dartmouth. All other existing oil-fired plants would be converted to coal by the time gas became available.

For Tufts Cove, the location made it difficult to bring in coal or to have a coal pile. It was proposed to operate the plant on gas for about two years at 50 per cent load factor, then two more years at about 15 per cent load factor. Thereafter, the plant would be retired.

Nova Scotia also proposed to convert gas turbine generators, seven units totalling approximately 200 MW, which presently burn #2 fuel oil to natural gas. Its witnesses testified that the Province had not discussed its plans with EMR.

Nova Scotia's estimated thermal load for the province is shown in Table 4-1. These figures were arrived at in consultation with Nova Scotia Power Corporation.

New Brunswick and Nova Scotia assumed that there would be a price differential between heavy fuel oil and natural gas sufficient to justify the proposed conversions.

Views of the Board. The Board notes that while the federal government in the NEP does not favour the long term use of natural gas to generate electricity as it might unduly delay the development of lower cost alternatives, interim use of gas while the generating plants are being converted to coal is not precluded.

The Board notes also that only the submissions of New Brunswick and Nova Scotia were prepared in collaboration with the provincial power utilities and contain specific proposals. The associated natural gas requirements are shown in columns 2 and 4 of Table 4-1. The Board accepts these figures as the expected maximum demand to supply the proposed conversions. The Board's forecast of thermal generation requirements reduced this maximum to account for pipeline capacity constraints. This forecast is shown in Table 4-2. The Board considers that the proposed conversions of oil-fired thermal generation to natural gas for an interim period would conform to the provisions of the NEP and are, therefore, acceptable.

TABLE 4-1

TRANS QUEBEC & MARITIMES PIPELINE INC.

POTENTIAL THERMAL LOADS[1]

(Petajoules)

	New Brunswick		Nova Scotia	
	(2)	(3)	(4)	(5)
Year	Province of New Brunswick	ICG Brunswick Gas Ltd.	Province of Nova Scotia	ICG Scotia Gas Ltd.
1982	2.34	2.08	-	-
1983	12.26	12.47	-	1.4
1984	12.95	12.47	16.26	8.3
1985	11.31	12.47	16.26	8.3
1986	1.95	12.47	16.26	2.1
1987	1.95	12.47	5.81	0
1988	1.95	12.47	5.81	0
1989	1.95	12.47	5.81	0
1990	1.95	12.47	5.81	0
1991	1.95	12.47	5.81	0

NOTES: (1) Table is based on similar table submitted by TQM (Exhibit 217)

(2) Submission of the Province of New Brunswick, Table 4, Page 15, February 1981. Includes Coleson Cove 93 x 335 MW) to 1985 and Courtenay Bay #2 (13 MW) throughout. (Exhibit 121)

(3) Submission of ICG Brunswick Gas Ltd. dated March 6, 1981, table after page 3, "Customer Attachment and revenue Schedule." (Exhibit 71)

(4) Submission of the Province of Nova Scotia, dated February 1981, Table 2.5 and Fig. 2.1, includes Tufts Cove and gas turbines. (Exhibit 127)

(5) Submission of ICG Scotia Gas Ltd., dated March 6, 1981, Schedule 1. (Exhibit 249)

TABLE 4-2

DEMAND FOR NATURAL GAS - NEW BRUNSWICK AND NOVA SCOTIA

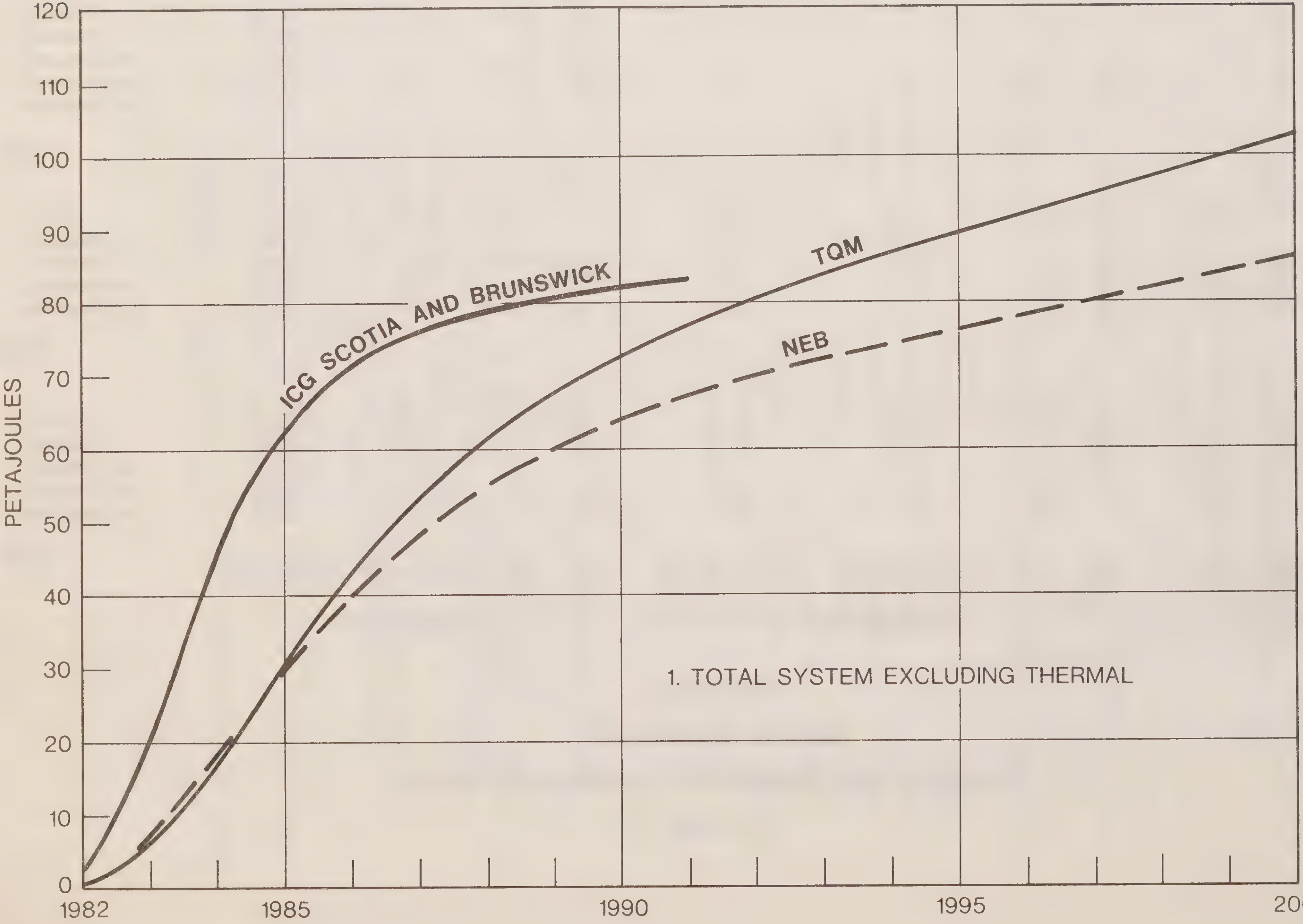
COMPARISON OF FORECASTS

(Petajoules)

	NOVA SCOTIA				NEW BRUNSWICK				TOTAL		
	Nova Scotia	ICG Scotia	TQM	NEB	New Brunswick	ICG Brunswick	TQM	NEB	ICG	TQM	NEB
1985											
Residential	8.5	2.7	3.5	2.6	3.6	3.4	4.4	3.1	6.1	7.9	5.7
Commercial	3.1	9.1	2.4	1.8	5.6	8.8	3.0	2.1	17.9	5.4	3.9
Industrial	9.3	8.4	4.0	7.2	18.5	31.7	13.4	14.4	40.1	17.4	21.6
Thermal	16.3	8.3	-	16.7	11.3	12.7	-	11.8	12.7	-	28.5
Total	37.2	28.5	9.9	28.3	39.0	56.6	20.8	31.4	76.8	30.8	59.7
1990											
Residential	11.7	8.4	10.3	7.3	5.8	6.6	10.2	7.3	15.0	20.5	14.6
Commercial	7.7	14.6	7.1	5.2	7.1	12.0	7.0	5.3	26.6	14.1	10.5
Industrial	10.2	8.4	12.6	16.2	20.6	31.8	26.2	22.8	40.2	38.8	39.0
Thermal	5.8	-	-	-	2.0	12.7	-	-	12.7	-	-
Total	35.4	31.4	30.0	28.7	35.5	63.1	43.4	35.4	94.5	73.4	64.1
2000											
Residential	16.1	-	13.9	10.9	-	-	13.3	10.3	-	27.2	21.2
Commercial	15.8	-	9.6	8.9	-	-	9.1	8.4		18.7	17.3
Industrial	12.4	-	18.9	19.8	-	-	38.2	27.7	-	57.1	47.5
Thermal	1.3	-	-	-	-	-	-	-	-	-	-
Total	45.6	-	42.4	39.6	-	-	60.6	46.4	-	103.0	86.0

Figure 4–1

NET SALES OF NATURAL GAS – NEW BRUNSWICK AND NOVA SCOTIA
COMPARISON OF FORECASTS[1]



CHAPTER 5
NATURAL GAS SUPPLY

5.1 Conventional Gas Supply

Evidence of the Applicant. TQM stated that it had received assurances from TCPL and Pan-Alberta for the supply of natural gas for the new markets, with TCPL providing supply in the initial years of the project. Commencing 1 November 1985, Pan-Alberta would supply 30 per cent of the market in that contract year, 40 per cent the following year, and 50 per cent in subsequent years, with TCPL providing the balance in each year. The Pan-Alberta quantities would be sold to TCPL at a point just east of the Alberta-Saskatchewan border.

Pan-Alberta relied upon its supply data previously submitted to both the NEB and the AERCB. TCPL relied upon supply data previously submitted to the NEB in the Omnibus Gas Hearing (GH-4-79) and resubmitted selected data from the recent Total Energy Inquiry (EHR-1-80). Both Pan-Alberta and TCPL were confident that they had adequate supply available in Alberta over the short term and could contract for any additional gas required to meet the TQM market in later years.

Views of the Board. The Board is satisfied that Pan-Alberta and TCPL have adequate supply capability from currently contracted reserves to meet their present requirements and those of the TQM market until 1987. The Board is aware that there is adequate supply in Alberta beyond that date to meet foreseen requirements for the domestic market. The Board considers that they will be able to contract for the additional gas needed to meet any future requirements.

5.2 Sable Island

Evidence of the Applicant. TQM made no studies of its own with respect to threshold levels, on-stream dates, or production rates for Sable Island gas, but regarded

the estimate of 1 November 1987 by Mobil, the operator of the development, as being the earliest possible date for production from the area. TQM believed that it was impossible to determine a precise date by which the gas could be available pending further drilling. In the light of Mobil's evidence with regard to the implications of the NEP, TQM was of the opinion that there was significant uncertainty about an onstream date of November 1987. The Company noted that Sable Island gas might never be produced.

TQM believed, however, that the existence of a readily-reversible pipeline in the Maritimes would reduce the required threshold level of reserves and would aid in bringing Sable Island gas to market. TQM's sponsoring companies stated that they would not let long-term contracts between TQM and TCPL and Pan-Alberta stand in the way of Sable Island gas entering the Maritime market. They felt that there would be sufficient lead time to permit negotiations to take place for the sharing of that market.

Views of the Intervenors. Mobil stated that its studies to determine the economic viability of continuing its drilling program in the Sable Island area indicated that a minimum economic threshold level of 85 billion cubic metres with a base production rate of 12.75 million cubic metres per day would be required.

Mobil supplied information which indicated that the Venture structure extended further to the west than previously thought. Accordingly, it had increased its estimate of proven, probable and possible reserves for Venture to just over 85 billion cubic metres, subject to confirmation by additional drilling. Mobil stated that tests carried out on cores from Venture indicated that there should be no major problems in producing from the over-pressured sands.

Mobil will have two rigs operating in the area during the next year and felt that the earliest completion date for the appraisal program would be mid-1982 after the completion of a new Venture well. Mobil stated that this would make November 1987 the earliest possible start-up date for Sable Island gas production. It recognized that attaining that start-up date would require a number of events to occur favourably and sequentially and that slippage of this date was possible.

Mobil remained neutral with respect to the pipeline indicating that it had no effect on the economic threshold level but that it could probably aid in the marketing of Sable Island gas when production commenced.

Nova Scotia stated that based on discussions with the companies operating in the area, it estimated the minimum threshold level for commercial viability to be 57 million cubic metres. This estimate is based on the assumption that a pipeline would bring the gas to shore.

<u>Views of the Board</u>. The Board is aware that a natural gas supply potential exists in the Sable Island area. The Board accepts Mobil's estimate of 85 billion cubic metres as a threshold level and production rate of 12.75 million cubic metres per day as reasonable. However, at this time there are insufficient data to confirm that the quantities of natural gas necessary for economic production exist in the Sable Island area.

The Board recognizes that depending upon the results of the appraisal program Mobil may be able to proceed with the project by mid-1982 after the completion of the proposed Venture well. This could result in gas flowing from the Sable Island area by November, 1987; however, this date may be optimistic.

Due to these uncertainties, the Board is unable to determine at this time with precision whether an economic threshold level will be attained in the Sable Island area and, if so, when this level will be attained.

CHAPTER 6

ENGINEERING, RIGHT-OF-WAY, AND ENVIRONMENTAL MATTERS

6.1 Location

Evidence of the Applicant

Introduction. The pipeline facilities proposed by TQM would commence downstream of Lévis/Lauzon and would serve new market areas in New Brunswick and Nova Scotia. They consist of approximately 736.9 km of mainline between Lévis/Lauzon in Quebec and the junction with the Glace Bay lateral in Nova Scotia, 1006.6 km of laterals and sub-laterals, seven compressor stations having a total power of 22,000 kW, and meter stations located at each of the 31 delivery points.

Details of those facilities are provided in Tables 6-1 and 6-2.

Route Selection. The route selected by TQM was essentially the same as that proposed by Q & M. According to TQM, route refinements would be made in final design and would reflect adjustments made after contact with landowners.

Reference was made by the Applicant to the feasibility of relocating certain portions of the mainline after certification of the facilities.

One such relocation concerned the mainline route proposed by TQM west of La Pocatière, which runs south of and parallel to Autoroute 20 at a distance varying from one to four km from the highway. TQM indicated that the question of relocating the mainline north and adjacent to Autoroute 20 (to provide access to additional potential markets along the highway between Montmagny and La Pocatière) would be reviewed in final design in consultation with the Province of Quebec. Such review would consider agricultural, environmental, and engineering factors. If the mainline were to remain south of Autoroute 20, TQM would then propose to install sales taps on its mainline to permit future connections of the potential

TABLE 6 - 1

SUMMARY OF MAINLINE FACILITIES

SECTION	PIPE LENGTH (km)	PIPE SIZE (mm)	MOP (kPa)	COMPRESSOR STATION NO.	COMPRESSOR STATION LOCATION	COMPRESSOR STATION UNIT NO.	TYPE	SIZE (kW)	YEAR OF CONSTRUCTION		
Lévis/Lauzon to Quebec/ New Brunswick Border	195.5	457	8275	QB30	St-Nicolas	1	Electric	1500	1984		
						3	Gas	1500	1984	1986	1988
				QB40	St-Eugène	1	Electric	1250		1986	
						2	Gas	1250		1986	1988
				QB50	St-Athanase	3	Gas	1250		1986(2)	1988
Quebec/New Brunswick Border to New Brunswick/ Nova Scotia Border	460.6	457	8275	NB10	Rivière Verte	3	Gas	1250		1986(2)	1988
				NB20	Cloverdale	3	Gas	1000	1984(2)		1988
New Brunswick/ Nova Scotia Border to the Glace Bay Lateral Junction	80.8	457	8275	NSL-1	New Annan	1	Gas	1250			1988
				NSL-2	New Annan	2	Gas	250			1988(2)

NOTE: (2) Number inside the bracket indicates the number of units installed during the year.

Table 6-2

LATERALS AND SUB-LATERALS IN NEW BRUNSWICK AND NOVA SCOTIA

Area Served	Pipe Length	Pipe Size	Construction Year
	(km)	(mm)	
New Brunswick			
Bathurst	3.4	114.3	1983
Belledune	6.4	114.3	1983
Campbellton	6.0	114.3	1983
Chatham	5.5	114.3	1984
Dalhousie	7.6	114.3	1983
Edmundston	1.9	114.3	1982
Fredericton North (Marysville)	6.4	114.3	1982
Fredericton	9.3	114.3	1982
Grand Bay	1.9	114.3	1983
Havelock	14.6	114.3	1983
Moncton	13.8	168.3	1983
Nackawic	14.0	114.3	1982
Newcastle	131.6	273.1	1983
	64.4	219.1	1983
	34.0	168.3	1984
	61.5	168.3	1984
	6.3	114.3	1984
Oromocto	6.6	114.3	1982
Sackville	4.7	114.3	1983
Saint John	19.1	273.1	1982
	79.2	219.1	1982
Sussex	5.5	114.3	1983
Westfield	1.8	114.3	1982

Table 6-2 (continued)

LATERALS AND SUB-LATERALS IN NEW BRUNSWICK AND NOVA SCOTIA

Area Served	Pipe Length (km)	Pipe Size (mm)	Construction Year
Nova Scotia			
Amherst	4.0	114.3	1983
Antigonish	3.2	114.3	1984
Dartmouth	18.7	168.3	1983
Glace Bay	163.6	273.1	1984
	110.1	219.1	1984
	18.3	168.3	1984
Halifax	99.8	323.9	1983
	30.1	273.1	1983
New Glasgow	3.7	114.3	1984
North Sydney (Sydney Mines)	2.3	168.3	1984
	20.1	114.3	1984
Port Hawkesbury	6.4	114.3	1984
Springhill	10.3	114.3	1983
Stellarton	2.9	114.3	1984
Sydney	2.3	114.3	1984
Truro	5.3	114.3	1983

markets between Montmagny and La Pocatière without interrupting the flow of gas through the mainline.

TQM also indicated that the feasibility of relocating the mainline along Autoroute 20 between La Pocatière and Rivière-du-Loup and along Highway 185 between Rivière-du-Loup and Cabano would be reviewed in final design in consultation with the Province of Quebec. This potential mainline deviation would result from environmental and agricultural considerations and would not be intended primarily to serve additional markets. TQM indicated that a further review of agricultural, environmental, engineering, and economic factors would be necessary to justify a mainline relocation. This deviation would require a 30 km addition to the proposed mainline and result in additional expenses of about \$9 million (1980 dollars, direct cost only).

In the Province of New Brunswick the NBFA, supported by the Province, recommended that a relocation of the mainline out of the floodplain between Maugerville and Sheffield be seriously considered by TQM in order to avoid engineering and agricultural problems. In addition to the agricultural concerns discussed in a later section of this report, the Federation stated that the Maugerville/ Sheffield area was a plain inundated by flood waters almost every year, and construction of the pipeline could be complicated by engineering problems.

TQM stated that its current view was that both routes were technically and environmentally acceptable, but undertook to investigate this potential rerouting of the mainline with the Province during final design. An additional \$12 million (1980 base, direct cost only) would be required for a relocation north of Grand Lake.

Views of the Board. The Board is satisfied with the general location of the proposed pipeline route. The Board finds that the additional length of mainline for the relocation west of La Pocatière would probably be less than 10 km and could represent an additional investment in the order of $2 million (1980 dollars, direct costs only). The Board finds that the evidence currently on the record does not justify a mainline rerouting north of Autoroute 20.

With regard to the possible mainline deviation around Rivière-du-Loup, the absence of specific environmental or agricultural reasons to relocate, combined with the additional costs associated with this potential rerouting, leads the Board to conclude that the applied-for route is the better alternative.

The Board agrees with TQM that either route within or outside of the floodplain between Maugerville and Sheffield is technically feasible and accepts as reasonable the estimated difference in cost of $12 million. The Board believes that the information currently available on the Grand Lake relocation does not warrant a mainline relocation at this time.

6.2 Design and Capacity

6.2.1 Design Methodology

Evidence of the Applicant. The mainline was designed to transport the largest of the peak day, winter average day, or summer average day volumes in each mainline section using an economic and reliable combination of pipe, compression, and peak shaving facilities.

The laterals and sub-laterals were sized for the maximum required volumes from the mainline to each delivery point.

The mainline was sectioned by the Applicant as follows:

(1) Mainline Section 1: 518.2 km; St-Nicolas to Saint John Lateral Junction;
(2) Mainline Section 2: 86.5 km; Saint John Lateral Junction to Sussex Lateral Junction;
(3) Mainline Section 3: 185.3 km; Sussex Lateral Junction to Glace Bay Lateral Junction.

Before adopting its most appropriate system design, TQM studied other system alternatives and compared them on a capital cost and cumulative present value cost of service basis with its proposed design. TQM adopted a nominal pipe diameter of 457 mm for its mainline between Saint John Junction and Sussex Junction. Although the cumulative discounted cost of service for this alternative was marginally higher (less than one per cent) than for another alternative with a diameter size of 406 mm, TQM believed that the benefits from system security, potential reversibility, and uniformity would offset the increased costs.

Views of the Board. Based on TQM's and the Board's demand forecasts, the Board finds TQM's design of the mainline, laterals, and sub-laterals to be acceptable.

6.2.2 Underground Storage and Load Factor Matters.

Evidence of the Applicant. As an integral part of the overall system design, TQM proposed underground storage facilities to be located near Sussex, New Brunswick at a cost of $62.5 million (1980 dollars) to satisfy the forecast gas demand under severe winter conditions. TQM pointed out that underground storage facilities were not part of the application, but indicated its intention to file a site-specific application for these facilities, approximately six months after issuance of a certificate for pipeline facilities.

Though TQM had not yet signed a contract with Pan-Alberta and TCPL, its shippers, it had been agreed that gas would be delivered into the TQM system at an annual load factor of 85 per cent. From load duration data, TQM determined the annual market load factor at which distributors would receive gas at the city-gate. Table 6-3 illustrates TQM's forecast market load factors for the contract years commencing 1 November 1986 and 1990.

TABLE 6-3

TQM

Regional Market Load Factors

(Per Cent)

Year	Quebec	New Brunswick	Nova Scotia	Average Maritimes	Average TQM System
1986/87	77.2	92	60	77.0	77
1990/91	72.2	82	58	69.7	71

The underground storage facilities would allow the distributor to purchase gas at an 85 per cent load factor. Since the distributor's valley gas would be stored during the summer, the distributor would bear the carrying charge between the time gas is purchased from TQM and placed in storage until gas is delivered at the city-gate the following winter. TQM proposed that the cost of service of underground storage be included in the total TQM cost of service.

The total capacity required in 1990/91 was estimated to be 418.9 million cubic metres and would be provided by developing 17 caverns, each having a gross storage capacity of 34 million cubic metres. The Applicant estimated that underground storage would be required by the 1985-86 heating year. Prior to 1985-86, TQM would have to rely on line pack gas from upstream to bridge the gap between the supply and market load factor. The Company was confident that such

peaking gas could be obtained. TQM indicated that approximately one quarter of the total underground storage requirements would be required to service the Maritimes. The remainder would be needed to serve markets in Quebec.

According to TQM, underground storage would provide peak shaving services at significantly lower cost than either LNG facilities of similar capacity, or several dispersed peak shaving facilities operated by distributors, or reliance on upstream facilities which would need to be oversized to handle the forecast demand. TQM indicated that in a no-storage case the diameter for the mainline section between the Quebec City junction and the Saint John lateral junction would have to be increased from 457 mm to 508 mm to meet the forecast demand in operating year 1990/91. TQM estimated the critical date of procurement decision for this mainline section to be 1 December 1981.

TQM indicated that a six-month confirmatory drilling program, planned to start immediately after certification of the pipeline facilities, would be required to ascertain the technical feasibility of the construction of underground salt caverns and to determine the design parameters of the facilities. The cost of this drilling program was estimated by TQM to be approximately $500,000 for each site location.

The Sussex site would be investigated first. If this potential site were not found to be suitable for construction of underground salt caverns, TQM would then look at an alternative site located near Dorchester.

Views of the Board. The Board notes that, although the Applicant has not applied for underground storage facilities at this time, nonetheless, they form an integral part of the decision for the application for pipeline facilities. In these proceedings, the Applicant has not demonstrated to the satisfaction of the Board that the underground storage proposed at Sussex is the best available alternative to provide peak shaving service to the TQM system.

The Board notes that if, for technical and environmental reasons, the underground storage could not be constructed but markets were to develop as forecast by the Applicant, a larger diameter mainline between the Quebec City junction and the Saint John lateral junction would be required.

The Board notes that the salt cavern storage is needed to balance the pipeline facilities as a whole from St-Lazare to Halifax, both those already certificated as well as the Maritimes portion of the line. The Board further notes that three-quarters of the capacity is needed to serve the Quebec market and the remainder to serve the Maritimes market. The problem, in the Board's view, is not significant in relation to the total project and is one that the Board will require to be resolved between the period after certification and before construction starts. Therefore, in view of the uncertainties of the technical feasibility of developing salt caverns and because of the risk of approving an inappropriate line size between Lévis/Lauzon and the Saint John lateral junction, the Board requires that TQM's submission to the Board for approval of the final design of the pipeline facilities be supported by a study demonstrating:

(1) the technical feasibility and the environmental impact of underground salt cavern storage facilities in New Brunswick based on the results of a confirmatory drilling program; and

(2) the economic advantages of providing peaking gas to distributors in the Provinces of Quebec, New Brunswick, and Nova Scotia by using underground storage facilities in the Province of New Brunswick as compared to other alternatives including underground storage in the Province of Ontario.

6.2.3 System Reliability

Evidence of the Applicant. TQM performed a reliability study of its mainline system assuming compressor unit outages under peak day, winter average day, and summer average day flow conditions during the 1990/91 design year. For each condition, a reserve unit was assumed to be out of operation and individual unit outages at all operating stations were examined. Under such conditions the reduction in deliverability in the affected area varied from zero to eight per cent.

During cross-examination, TQM agreed that before making a decision to install reserve units on the mainline, it would take account of several years of operating experience to determine from a reliability standpoint whether they were required or not.

TQM's total facilities as applied for included the installation of four compressor units in 1984, seven compressor units in 1986, and eight compressor units in 1988 (see Table 6-1). Each unit could be installed within a period of 18 months (including detailed engineering and ordering of the equipment). Although the application requested certification of all the compressor facilities, TQM would, however, be satisfied with approval only for the compressor facilities needed in November 1984 since it was somewhat difficult to forecast with accuracy what the gas requirements would be in the future.

Views of the Board. The Board is prepared to approve the compression facilities scheduled to be in service in November 1984, namely, one 1500 kW electrically-driven and one 1500 kW gas-driven reciprocating compressors at Station QB30 and two 1000 kW gas-driven reciprocating compressor at Station NB20.

6.2.4 Metallurgical Criteria.

Evidence of the Applicant. The Applicant performed a fracture control analysis to ensure that the specified materials properties would prevent brittle fracture and would minimize ductile fracture. With respect to ductile fracture arrest, the Applicant initially proposed to specify the mean fracture toughness for all pipe diameters for which the mean value was less than the specified minimum fracture toughness value based on limiting initiation. Subsequently, because of anticipated price advantages, the Applicant felt that it would receive sufficient fracture toughness for 457 mm diameter pipe by specifying a minimum fracture toughness of 34 J, even though the required fracture toughness for self-arrest was 59 J.

Views of the Board. The Board has reviewed the metallurgical criteria and considers that the required materials properties resulting from the design analysis must be reflected in the materials specifications. The Board, therefore, requires that the arrest toughness value for pipe (CSA Standard Z-184-M1979, note to Clause 3.1.2.7) be specified for the 457 mm diameter pipe in the final materials specifications as an all heat average for each individual order. The values specified for minimum yield strength and minimum fracture toughness for the line pipe are acceptable to the Board.

6.2.5 Canadian Content

Evidence of the Applicant. With respect to Canadian content, TQM stated that it relied on evidence presented by Q & M in its earlier application, which indicated a buying policy to maximize the net benefit of the project to the market area and Canada subject to competitive price, quality, and delivery requirements.

Data filed by TQM indicated the average Canadian content of the project to be 94 per cent, based on capital expenditure of $394 million in 1980 dollars. TQM provided a breakdown of its total expenditure indicating the Canadian content of materials and installation by major expenditure categories. This is summarized in Table 6-4.

Views of the Board. The Board is satisfied with the approach taken by TQM to estimate Canadian content and finds its estimate to be reasonable.

The Board will require TQM to file a report with the Board, within 12 months after leave to open is granted, indicating for each category in Table 6-4 the percentage of Canadian content achieved in comparison to the estimates, and the reasons for any variations.

6.2.6 Impact of Offshore Alternatives

Evidence of the Applicant. At the request of the Board, TQM provided a study of the impact of future Sable Island gas supplies on its system configuration with a range of supply and start-up dates.

TQM used a maximum supply rate based on Mobil's estimate of potential flow of 12.75 million cubic metres per day. Such flow would require either looping of the mainline between the St-Nicolas junction and the Glace Bay lateral junction with 457 mm loop line or in the "prebuild" scenario installing 610 mm diameter pipeline as opposed to the proposed 457 mm diameter pipeline for the base case. TQM did not propose to initially build larger facilities designed to transport future supplies from Sable Island because of the uncertainties associated with the potential flow and in-service date of Sable Island gas.

The results of TQM's study on the cost of additional facilities to accommodate Sable Island gas are shown in Table

Table 6-4
TQM Estimate of Canadian Content (1)

	Expenditures ($1980 millions)			
	Total	Canadian Content	Non-Canadian Content	Canadian Content Percentage
Land and Land Rights	9.2	9.2	-	100.0
Pipeline				
- Materials	103.9	93.5	10.4	90
- Installation	159.4	154.4	5.0	95
- Sub-total	263.3	247.9	15.4	94
Compressor Stations				
- Materials	25.3	20.2	5.1	80
- Installation	10.8	10.3	0.5	95
- Sub-total	36.1	30.5	5.6	85
Meter Station				
- Materials	1.5	1.1	0.4	75
- Installation	2.4	2.4	-	100
- Sub-total	3.9	3.5	0.4	90
Division & District				
- Materials	8.6	6.8	1.8	80
- Installation	2.7	2.6	0.1	95
- Sub-total	11.3	9.4	1.9	84
Communications				
- Materials	2.5	2.2	0.3	85
- Installation	1.1	1.1	-	100
- Sub-total	3.6	3.3	0.3	92
Total Direct Costs(2)	327.4	303.8	23.6	93
Indirect Costs (3)	66.5	64.9	1.6	97
Total Costs	393.9	368.7	25.2	94

(1) Based on Exhibit 29.
(2) Total direct costs do not include peak shaving facilities.
(3) Includes Engineering, Project Management and Contingency.

6-5. Assuming a start-up date of November 1987, the saving in capital cost of prebuilding versus looping for 12.75 million cubic metres per day would be $378 million, escalated, and the saving in cost of service from year 1980 to year 2015, discounted at 14.25 per cent to 1980, would be $152 million. TQM indicated that it would be prepared to prebuild the facilities if suitable arrangements could be made to finance them. It would also be prepared to file with the Board new proposals for a system capable of carrying offshore gas if at any time prior to the commencement of construction the supply of offshore gas should prove more assured. TQM indicated that the critical dates of pipe procurement for its system subject to prebuilding versus looping varied between 1 December 1981 and 1 December 1983.

To ensure the reversibility of flow at compressor stations on its system without interrupting gas service to its customers, TQM proposed to install all necessary connections during the initial construction of the project.

Views of the Intervenors. Mobil was of the opinion that it would be very difficult to justify pre-investment in a constant diameter or a large diameter line all the way to the east coast at this time.

New Brunswick recommended that the prebuild option be retained and that the additional cost be borne by the Government of Canada until such time as Sable Island gas becomes available. The Province maintained that there was a high probability that gas would become available from Sable Island by the late 1980's. It was concerned that if no prebuilding occurred, further environmental damage might have to be absorbed by landowners if a loop line had to be added two to three years after construction of the initial line.

TABLE 6-5

CAPITAL COST AND COST OF SERVICE COMPARISON BETWEEN PREBUILDING AND LOOPING FOR SABLE ISLAND SUPPLY

Sable Island Start-Up Date	Supply Rate	Capital Cost (1982-1991) Prebuild	Capital Cost (1982-1991) Loop	Difference	Current Cost of Service (1982-2015)(1) Prebuild	Current Cost of Service (1982-2015)(1) Loop	Current Cost of Service (1982-2015)(1) Difference
	(10^6 m^3/d)	(Escalated $ million)				($ million)	
1987	7.08	444	508	(64)	453	482	(29)
	12.75	602	980	(378)	628	780	(152)
1990	7.08	479	572	(93)	462	483	(21)
	12.75	693	1206	(513)	619	750	(131)

Note (1) Cost of service was discounted at 14.25 per cent to year 1980.

According to the Province, if the prebuilding was not authorized, the pipeline should be designed for reversibility in environmentally sensitive areas. The Province, however, indicated that it would revise its position if it were completely satisfied that no hardship or financial loss to the landowner and that no environmental damage would occur.

The Province of Nova Scotia commissioned an investigation into the construction and operating costs of prebuilding and the cost of future looping of the proposed TQM system. Nova Scotia concluded that the initial construction of the prebuild alternative for 12.75 million cubic metres per day from Sable Island was the better alternative, even if there were a delay in Sable Island production until after 1990. The Province estimated that the net premium associated with prebuilding, assuming no Sable Island gas production by 2009, would amount to $69 million (1981 dollars) at a real discount rate of 10 per cent in terms of capital costs and operating and fuel costs. It was not however, prepared to commit any funds to enable prebuild facilities to be constructed.

<u>Views of the Board</u>. The Board agrees that the earliest date at which Sable Island gas could be available onshore is November 1987, and finds that the potential savings obtained in the prebuild case are less than the potential losses if Sable Island gas does not come onshore. However, as indicated in Chapter 5, the Board cannot determine at this time when or if an economic threshold level will be attained in the Sable Island area. There are many uncertainties regarding the availability of Sable Island gas, but if all of them were removed the savings obtained would be significant enough, both in terms of capital and operating costs, to justify the construction at the present time of a larger diameter pipe capable of handling an average flow of 12.75 million cubic metres per day.

In the face of uncertainty about Sable Island gas, and in the absence of any party willing to finance prebuild facilities, the Board is not prepared at this time to recommend the certification of facilities to accommodate Sable Island gas additional to those facilities proposed by the Applicant.

6.2.7 Construction Schedule

Evidence of the Applicant. TQM proposed to start construction of the pipeline facilities in the winter of 1981-82 and finish in the summer of 1984. Some advance clearing of the mainline between Lévis/Lauzon and the New Brunswick border was proposed to take place in early September 1981.

Evidence showed that many factors beyond the control of TQM could delay the schedule of construction. The main factors were:

(1) negotiations with provincial governments in terms of satisfying their environmental and agricultural concerns;
(2) bill C-60, which is likely to necessitate additional public hearings;
(3) conditions in the Board's certificate;
(4) appointment of distributors;
(5) negotiations with landowners;
(6) acquisition of rights-of-way; and
(7) progress of construction of facilities approved under Certificates GC-64 and GC-65.

Views of the Board. The Board doubts that the construction schedule prepared by TQM can be met. It appears that considerable delay could occur both in the construction start-up date and the completion date of the project.

6.3 Cost of Facilities

6.3.1 Transmission Facilities.

Evidence of the Applicant. The capital cost of the proposed facilities, excluding costs associated with storage facilities, was estimated to be $393,759,000 (1980 dollars). Details are provided in Table 6-6.

Table 6-6

Estimated Cost of TQM Transmission Facilities

($ Thousands 1980)

Direct Costs	
Land and Land Rights	$ 9,164
Pipeline	263,280
Compressor Stations	35,944
Meter Stations	3,953
Division and District	11,250
Communications	3,617
Sub-Total Direct Cost	327,208
Indirect Costs	
Pre-Permit Engineering	$ 11,855
Engineering (Indirect Cost)	18,602
Management and Overhead	14,763
Contingency	17,152
N.E.B. Monitoring	2,839
O & M Prior to Service	1,340
Sub-Total Indirect Cost	$ 66,551
TOTAL	$393,759

With the exclusion of the costs incurred beyond 1984 for the compressor units and storage facilities, the cost of the project in 1980 dollars would be $360 million.

The escalated total cost of the pipeline facilities, excluding costs associated with storage facilities, was estimated to be $611,773,000 (including allowance for funds used during construction of $79,434,000). TQM's escalated cost of the proposed facilities was based on annual average inflation rates of approximately 10.5 per cent.

Views of the Board. Based on the evidence in these proceedings, the Board finds that, subject to final design changes resulting from site-specific terrain analysis and possible route deviations, TQM's cost estimates shown in Table 6-6 are reasonable. However, the Board will require that the Applicant submit its final estimate of the cost of the pipeline facilities, which cost shall be based on the final design and specifications for the pipeline.

6.3.2 Upstream Facilities

Evidence of the Applicant. TQM provided an estimate of the cost of the additional facilities required to be installed on the existing TCPL system to accommodate the volumes of gas to be sold in the Maritimes. This estimate is shown on Table 6-7.

Views of the Board. The Board recognizes that the incremental costs of the upstream facilities provide only an order of magnitude estimate. In addition, the Board realizes that there is a TCPL application pending, for a North Bay shortcut, and the decision on that application could affect the cost of the upstream facilities. Under the circumstances, the Board accepts the cost estimate for the upstream facilities provided by TQM as reasonable.

Table 6-7

Estimated Incremental Capital Cost of Upstream Facilities

($ Million Current)

YEAR	PIPELINE	COMPRESSORS	TOTAL CAPITAL COST
1981	0	0	0
1982	21	7	28
1983	42	13	55
1984	55	18	73
1985	69	22	91
1986	49	16	65
1987	52	17	69
1988	58	18	76
1989	22	7	29
1990	34	11	45
TOTAL	402	129	531

6.4 Right-of-Way

Evidence of the Applicant. TQM stated that it would secure, either by servitude or easement, a right-of-way based on the following pipeline diameters:

(1) 30.48 m for pipeline diameters 1066.8 mm to 508.0 mm;

(2) 22.86 m for pipeline diameters 406.4 mm to 304.8 mm;

(3) 18.288 m for pipeline diameters 254.0 mm to 101.6 mm.

TQM stated that it planned to construct seven compressor stations and 31 meter stations. The Applicant testified that it did not anticipate difficulties in obtaining sufficient fee lands for compressor and meter station sites.

Views of the Board. The planned right-of-way widths submitted by TQM are acceptable to the Board, and the Board is satisfied that the Applicant can obtain all lands required for compressor and meter station sites.

6.5 Environmental Impact

Evidence of the Applicant. In the preparation of its case on the environmental impact of the project, the Applicant relied on evidence adduced at the hearing of the Q & M application, and on additional information provided in the TQM proceedings. As part of this additional information, the Applicant prepared an environmental update on route refinement which described the route selection process, activity at the post-certificate stage, and final design procedures. Also provided were environmental guidelines describing the environmental quality control program, legislation and regulatory requirements, environmental objectives, and environmental construction procedures for the pipeline and ancillary facilities. TQM submitted revised construction drawings on the route alignment indicating the construction scheduling of the project.

The Applicant stated that it would follow the requirements of all federal and provincial statutes, and, where they overlap, TQM would adhere to the more stringent statute provisions, provided a provincial statute did not conflict with any certificate that the Board might issue. The Applicant indicated that it would conduct the additional environmental studies identified during the hearing. Upon acceptance by the Applicant, the recommendations of the consultants to minimize the environmental impact of the project would be incorporated into the construction schedule and written specifications.

The Applicant addressed other areas of concern raised during cross-examination of its witnesses. To avoid repetition, the Board has chosen to refer to the evidence adduced on these specific points at the time of expressing its view on the environmental impact of the project.

Views of the Intervenors. New Brunswick indicated concern relating to the impact of pipeline construction in the Maugerville-Sheffield floodplain and in other sensitive areas.

New Brunswick also expressed concern with respect to TQM's adherence to provincial statutes and the need for future co-operation with the Applicant in the project's development.

New Brunswick recommended that the Applicant route the pipeline adjacent to existing hydro corridors. If accepted, the recommendation would involve only one major rerouting, within the Maugerville-Sheffield area north of Grand Lake. New Brunswick accepted the Applicant's commitment to undertake detailed environmental studies upon certification to determine the merits of rerouting the pipeline north of Grand Lake. New Brunswick also recommended that the Applicant avoid, wherever possible, environmentally sensitive areas within the Province in the final alignment of the pipeline.

New Brunswick recommended that the Applicant develop the final alignment and scheduling of the project in close consultation with the Province. If accepted, the recommendation would minimize the concerns of the Provincial Departments of Agriculture, Environment and Natural Resources.

New Brunswick had expressed concern that undue haste in constructing the pipeline could result in unnecessary environmental damage. The Province indicated that it would not support any "shortcuts" in construction procedures permitting adverse environmental impacts of the project. The Province stated that the Applicant had cooperated with the Province regarding the development of the project to date. New Brunswick welcomed the Applicant's commitment to future cooperation with the Province in the development of the final design phase.

The UNBI expressed concern with the effects of construction on native Indian burial grounds, water supplies, fishing grounds, hunting territories, and the gathering of fiddleheads.

The NBFA stated dissatisfaction with routing the pipeline in the following sensitive areas: the potato belt of the upper Saint John valley, the Maugerville-Sheffield

floodplain south of Grand Lake, and the Sackville area where the maintenance of drainage is critical for agricultural land use. The Federation recommended that the Applicant route the pipeline within established rights-of-way to minimize the impact of construction upon farmland. The Federation recommended that the Applicant adhere to approved construction procedures and practices regarding soils and drainage to facilitate the continuation of farming activities. The Federation stressed the necessity to preserve topsoil on agricultural land.

Nova Scotia stated that all significant environmental impacts within the Province could be avoided or mitigated. Nova Scotia did not anticipate difficulty in obtaining the site-specific information required to ensure an assessment of the environmental impact of the project. Nova Scotia was satisfied the cooperation and liaison between the Applicant and the Province would continue in the development of the final design phase.

<u>Views of the Board</u>. Based on the evidence adduced in support of the application and given at the hearing, the Board is of the opinion that the Applicant is much more cognizant of the environmental impact of the pipeline project than during the previous hearing.

The Board notes that the Applicant's general environmental plans and procedures would reduce the effects of construction on fish resources, water quality, waterfowl, wildlife, and agricultural and forested lands. The Board will require that additional environmental studies recommended by the consultants in volumes 6A and 6B of the 1978 Q & M application be undertaken by TQM upon certification. The studies will provide site-specific mitigative measures to reduce the environmental impact of the project in the development of the final design phase.

The Board will require, prior to the commencement of construction, that the Applicant submit for approval the procedures manual and alignment sheets. These documents will indicate the site-specific mitigative measures the Applicant would implement in the pipeline contruction. The Board will require that the final design specifications include the requirements outlined in the Board's environmental information request letter dated 30 January 1981.

The Board accepts the Applicant's undertaking to provide additional environmental information based on further site-specific studies identified at the hearing. The Applicant testified that there would be sufficient time to accomplish these studies prior to the scheduled start of construction. The Applicant stated the detailed environmental studies would be completed in sequence with the project's development.

The Board will require that the Applicant submit a schedule indicating the filing dates of the procedures manual and alignment sheets for the protection of farmlands and the environment.

The Board is concerned that the Applicant's project development requires an extensive number of undertakings to be completed prior to commencement of construction. The Board recognizes that the Applicant testified that final design documents would be completed in sequence from Quebec to Nova Scotia. Notwithstanding the phased development of the project, the Board is concerned that the Applicant's involvement with further hearings, if required, as well as with final design specification approvals and with land acquisitions could prevent TQM from adhering to the construction schedule. The Board is also concerned that the construction schedule within each spread permits only a minimum degree of flexibility. Therefore the Board agrees with New Brunswick that undue haste in the construction of the project could result in unnecessary environmental damage.

The Board will require written notification of variations to the construction schedule. If it appeared that these variations would cause further environmental impacts, the Board would require the Applicant to include specific mitigative measures to reduce any related effects on fish resources, water quality, waterfowl, wildlife, and agricultural and forested lands.

The Board notes the Applicant has outlined the following aspects of the environmental inspection program: the staff qualifications, training program, responsibilities, authority, reporting procedures, staff assigned per construction spread, and working hours. The Board is satisfied that the environmental inspection program could reduce the adverse environmental impacts of the project.

The Board notes that the Applicant's testimony indicates all environmental mitigative undertakings and evidence given in the hearing would be included within written specifications to be binding upon the contractors. The Board will require that TQM cause its contractors and subcontractors to abide by the Applicant's environmental undertakings as a further assurance in reducing adverse environmental impacts of the project.

The Board notes the Applicant has not identified plans and procedures or the specific watercourses to be used for hydrostatic testing of the pipeline. The Board will require the Applicant to submit for approval the final design documents identifying the specific watercourses to be used and the related plans and procedures for hydrostatic testing which would minimize the environmental impact.

The Board notes the importance of restoration procedures to ensure long-term stability to the rights-of-way and to mitigate environmental concerns resulting from the project. The Board accepts the restoration plans and procedures outlined by the Applicant.

The Board notes that a detailed environmental monitoring and surveillance program would be necessary to maintain and ensure success of the restoration program. The Board will require the Applicant to submit for approval, prior to leave to open being granted, a detailed monitoring and surveillance program for the project.

In summary, on the basis of the evidence adduced on the question of the environmental impact of the project, the Board is satisfied that the pipeline facilities can be constructed in an environmentally acceptable manner, providing the Applicant fulfills the undertakings identified in the application and at the hearing, and adheres to its construction plans within each spread.

CHAPTER 7

LATERALS NOT APPLIED FOR

Evidence of the Applicant. TQM applied for new pipeline facilities composed of 736.9 km of mainline and 1 006.6 km of laterals and sub-laterals.

The possibility of serving new market areas in addition to those proposed by TQM was introduced by several intervenors. TQM stated that it would review the markets in these areas on an ongoing basis and that it would be prepared to construct the proposed laterals if they became economic.

Lateral Additions in Eastern Quebec. The Province of Quebec, ADEQ, CPIR, CRDEQ and Gaz Inter-Cité considered that the construction of a pipeline to the Maritimes should provide for gas service to the markets in the lower St. Lawrence area.

ADEQ proposed the construction of a lateral starting approximately at La Pocatière, running northeastward as far as Matane to serve the communities of Rivière-du-Loup, Rimouski, Mont-Joli, and Matane.

TQM provided a cost of service comparison between the Matane lateral and the Newcastle lateral based on its latest annual demand forecast. The Newcastle lateral was chosen by TQM as a yardstick in the evaluation of the cost effectiveness of any lateral addition on the system since it was the least cost-effective lateral on the entire TQM system. The comparison revealed that the lateral proposed by ADEQ would have a unit cost of service in 1990 of about $0.10 per cubic metre, approximately twice that of the Newcastle lateral of $0.05 per cubic metre in the same year.

A modified version of this lateral was also studied by the Applicant, whereby the Matane lateral would commence at Rivière-du-Loup. This modification assumed a re-routing of

the mainline via Rivière-du-Loup. Its unit cost of service in 1990 was calculated to be \$0.08 per cubic metre.

CPIR, supported by CRDEQ, proposed a combination of the Matane lateral and the Newcastle lateral, whereby the Rivière-du-Loup/Matane axis, the Matapedia Valley, and the Campbellton/Newcastle areas would be served by a single lateral. This would eliminate the need for the lateral section located between Madawaska and Campbellton at the beginning of the currently proposed Newcastle lateral. According to TQM, the Madawaska/Campbellton section covers a sparsely developed area and did not offer any substantial additional markets. The CPIR proposal would not affect the design of the mainline but could result in some savings in compression costs in this section.

TQM submitted a unit cost of service comparison between the CPIR proposal and the applied-for Newcastle lateral. The study showed that the unit cost of service of the CPIR lateral would be \$0.09 per cubic metre in 1990.

TQM did not propose to construct new laterals to serve the lower St. Lawrence area, but indicated additional facilities could be added if warranted.

The Applicant recognized that its choice of an economic cut-off point for laterals did not allow for the possible provision by the government of additional funds that could be used to improve the economics of any additional laterals proposed by intervenors. The Applicant stated that should funds be made available it would be prepared to seek authorization to construct these facilities as part of its transmission system. In the absence of such funds TQM testified that it would be willing to re-assess the economics of serving additional markets as changing conditions warranted.

At the request of the Board, TQM submitted the following estimate of capital cost contributions needed to lower the unit cost of service for certain laterals to a level

comparable to the unit cost of service on the Newcastle lateral for the operating year 1990.

SUB-LATERAL	CAPITAL COST OF CONSTRUCTION IN 1980 DOLLARS (DIRECT COST ONLY) ($ MILLION)	SUBSIDY REQUIRED IN 1980 DOLLARS (DIRECT COST ONLY) ($ MILLION)
Matane lateral, as proposed by ADEQ	15.5	7.44
Matane lateral, from Rivière-du-Loup in the "triangle" deviation case:	12.3	4.58
CPIR lateral (starting at La Pocatière)	65.4	27.05

<u>Nova Scotia South Shore and Valley Sub-Laterals.</u> Nova Scotia and ICG Scotia proposed an additional lateral starting from a point north of Halifax and terminating in the Annapolis Valley in the Waterville/Berwick area. In addition, the Province proposed the construction of a South Shore lateral starting from a point north of Halifax and running as far west as Liverpool.

TQM provided a unit cost of service comparison between these two potential laterals and the Newcastle lateral. This study revealed that the Annapolis Valley lateral would have a unit cost of service in 1990 of $0.064 per cubic metre, approximately 30 per cent higher than that of the Newcastle lateral. The South Shore lateral would have a unit cost of service in 1990 of $0.126 per cubic metre, more than twice that of the Newcastle lateral.

TQM reiterated its general policy that it would continue to review the markets for the new areas on an ongoing basis and that it would be prepared to consider building the new laterals should government funds be made available.

At the request of the Board, TQM submitted the following estimate of capital cost contributions needed to lower the unit cost of service of these two laterals to a

level comparable to that of the Newcastle lateral for the year 1990.

SUB-LATERAL	CAPITAL COST OF CONSTRUCTION IN 1980 DOLLARS (DIRECT COST ONLY) ($ MILLION)	SUBSIDY REQUIRED IN 1980 DOLLARS (DIRECT COST ONLY) ($ MILLION)
Annapolis Valley	7.5	1.65
South Shore	13.1	7.95

Views of the Intervenors. APMC considered that a provincial utility board is the appropriate body to assess the justification of proposed laterals and that funds should be made available under the NEP for laterals that are held to be uneconomic.

CPA did not accept TQM's economic criterion for deciding whether a lateral should be built and suggested that the Board should establish its own economic criterion.

IPAC objected to the construction of the Matane lateral and any possible future laterals for New Brunswick or Nova Scotia that were not part of this application. It felt that these laterals should be distribution laterals and as such could benefit from funds available under the NEP or from the provinces concerned.

Nova Scotia stated that, in order to provide natural gas service to as many areas in the Province as was possible, the transmission company should build the required laterals. The Province felt that funds available under the NEP could be used to assist in the construction of these laterals.

ADEQ, CPIR, and CRDEQ presented submissions that called for extension or re-routing of the Applicant's proposed pipeline to serve communities in their areas of concern. Accordingly, these organizations supported the construction of laterals by the transmission company, but were not averse to having the distributor build the laterals with funds from the NEP.

Views of the Board. The Board accepts the capital cost estimates supplied by TQM for the construction of the three possible lateral additions in Quebec and the Annapolis and South Shore laterals in Nova Scotia.

The Board has determined that it is unwarranted at this time, based on the evidence adduced at the hearing, to cause the Applicant to build any of these proposed additional laterals.

CHAPTER 8
CONTRACTS, TARIFFS AND FINANCING

8.1 Contracts

Evidence of the Applicant. The arrangements for the supply of gas for the TQM market were discussed in Chapter 5, dealing with natural gas supply. These arrangements were supported by a letter of agreement wherein TCPL and Pan-Alberta agreed to supply all gas required by TQM for a 20-year period.

TQM indicated that a transportation contract in the form attached to its pro forma tariff would be executed by TQM and TCPL for the transportation of the TCPL supply on the TCPL and TQM systems.

The sale of gas by TCPL to TQM would be made at a point immediately upstream of the various TQM delivery points at prices prescribed under the PAA. TQM filed a pro forma contract, to be approved by the Board, providing for the sale of gas by TCPL under its CD eastern zone rates, for a period of 20 years. The Applicant had assumed that the eastern zone would be extended to include the TQM system as proposed and that the prescribed prices in the zone would be the same in all areas for the same type of service. TQM stated that sales under the CD service contract would be at the system supply load factor level of 85 per cent.

As evidence of the final link in the contractual chain, TQM provided a pro forma contract for the sale of gas by TQM to the distributor on a CD service basis. The Applicant said that sales under this type of contract would be made at the same prescribed price as TQM paid TCPL. TQM stated it was possible to provide the distributor with an annual purchased load factor level of 85 per cent through the use of storage facilities, the cost of which would become part of TQM's cost of service rather than being charged to the distributor.

The Applicant stated that services such as Temporary Winter Service and Authorized Overrun Interruptible would be available to the distributor from TQM at prices similar to those charged by TCPL for these types of services in the existing eastern zone.

TQM further testified that executed contracts would be available for filing with the Board following its receiving certification of its proposed facilities, and following approval of the TCPL/TQM rates and tariff and the establishment of distributors in the Provinces of New Brunswick and Nova Scotia. The Applicant felt a condition in the certificate requiring the filing of executed contracts prior to construction would be acceptable.

TQM also indicated that, before it would consider starting construction or seeking leave to construct, signed sales contracts should be in place for gas requirements approximating the fourth year level of service on a firm basis for a 20-year period. In New Brunswick the appropriate level was considered to be 27.55 PJs for 1986 and in Nova Scotia it was considered to be 19.99 PJs for 1987.

Views of the Intervenors. ICG Brunswick advised that it had not discussed major contract terms with TQM. ICG Brunswick testified that, before signing any type of sales contract with the Applicant, it would first attempt to sign long-term contracts with its industrial and large commercial customers. Once it had signed contracts with its customers, ICG Brunswick would sign offsetting contracts with TQM.

ICG Scotia stated that it had had preliminary discussions with TQM in regard to contracts but there had been no formal negotiations. ICG Scotia testified that it had reviewed the pro forma contract presented by TQM and it would be willing to sign such an agreement.

Views of the Board. The Board is aware of the difficulties faced by the Applicant in providing finalized gas

supply contracts, transportation contracts, and sales contracts at this time. The Board would normally require that an applicant file copies of executed contracts for the sale of gas to the distributors and copies of transportation contracts at the time of the hearing. However, in the circumstances of this case, until certain issues relating to the tariffs are resolved, and until distributors are appointed in the Provinces of New Brunswick and Nova Scotia, it would be unrealistic to expect these documents to be available.

It is the Board's opinion that distributor contracts will be executed once the incentive measures contained in the NEP with respect to market development bonuses, conversion grants, and distributor viability, or some equivalent provisions, are implemented.

The Board will insist through the implementation of a condition that all relevant contracts, including supply contracts, transportation contracts, and sales contracts, be filed prior to commencement of construction.

With respect to sales contracts, because they are the key feature in the contracting process, compliance with the Board's condition implies that the level of sales volumes contracted be satisfactory to the Board.

8.2 Tariff Matters

8.2.1 Gas Transportation Tariff

Evidence of the Applicant. TQM filed a pro forma gas transportation tariff that set forth the rates and terms and conditions applicable to the gas transportation service to be provided by the Company. The Applicant stated that its tariff would be available to all shippers who would sign a long-term transportation contract. The tariff included a pro forma transportation service agreement to be executed between TQM and any shipper.

TQM stated that it would apply for the approval of a gas sales tariff and amend its tariff application before the Board. The tariff respecting the sale of gas by TQM to the

distributors would be similar to that currently in effect for sales of gas by TCPL to its existing customers.

Views of the Board. Under the terms of Order No. GH-1-81, the only application by TQM that was the subject matter of this hearing was for a certificate under Part III of the NEB Act. Since there was no application for the approval of a pro forma tariff under Part IV of the NEB Act in the present proceedings, the Board will defer to a subsequent hearing under Part IV any matters relating to the approval of any tariffs proposed by TQM.

8.2.2 Tariff Abatement Matters

Evidence of the Applicant. The TQM expansion to the Maritimes requires construction of a complete new pipeline transmission system. Under the natural gas pricing régime envisaged in the NEP, the TQM cost of service would be fully reflected in the Alberta border price and hence in the Alberta producer field-gate revenue. As a result, the higher incremental unit cost of transmission of the Maritimes extension would generate a negative producer revenue from the Maritimes sales in the early years of the project up to 1985. There would be an increasingly positive revenue from the Maritimes sales only after 1985.

In the Applicant's assessment, there would be a difference of $1 billion through the early years of the project between the producer revenue for a hypothetical situation where all sales were made in the Montreal market and the producer revenue if sales were made in areas east of Lévis/ Lauzon with no provision made for front-end help. The sponsors of TQM outlined the details of their contribution and proposed a federal contribution to provide for a positive producer revenue from the beginning of the project.

The sponsors, for their part, proposed to defer and capitalize the return on equity in the early years of the

project on a sliding scale and agreed also to accept the use of lower rates of depreciation in the initial years.

In the event of cost overruns, deferments of the return on equity and depreciation would adjust automatically to any changes in the capital cost of the project. The commitment of the sponsor contribution was stated to be firm whether or not there was any Federal Government subsidy.

The Applicant further proposed that the Federal Government should apply, from the $500 million fund outlined in the NEP, the sum of approximately $300 million, in 1981 dollars discounted at 12 per cent, to pay interest charges on TQM debt during the early years of the project. The interest contribution, when deducted from TQM's cost of service, would increase the revenue at the Alberta border in an equal amount. The Applicant proposed that the Federal Government's contribution towards interest payment should extend until the field-gate revenue approached 70 per cent of the average field-gate revenue from domestic sales in the Toronto-Montreal service area. TQM proposed that the interest abatement ($595 million, current dollars) should be extended for the 11-year period 1982 to 1992. The targeted 70 per cent field-gate netback allowed for all incremental costs including the upstream costs of the sales east of Lévis/Lauzon, and was said to be equivalent to a typical transaction arrangement between a producer and a petrochemical company in Alberta.

The Applicant also estimated the netback at the Alberta border from the sale of gas in the Maritimes compared with the netback from a sale in Montreal. The evidence shows that with the proposed sponsor and Federal Government contributions, the Maritimes revenue expressed as a percentage of the Montreal revenue would be in the low 60's in the early years but would increase to the high 70's in 1985 and to 87 per cent in 2000.

Views of the Intervenors. Intervenors representing producers' interests expressed concern at the diminution of

producer revenue on account of the sale of gas to the Maritimes, and called for a federal subsidy. These views are discussed in greater detail in the section dealing with economic viability.

Views of the Board. The Board finds that, without the tariff levelling proposed by TQM, the expansion of the TQM pipeline system into the Maritimes would generate a negative revenue to the Alberta producers from the Maritimes sales volumes in the initial years of service. The contribution from the Federal Government and the deferral of the return on equity and lower rates of depreciation in the early years proposed by the sponsors of TQM would alleviate such a situation. The Board notes that the Federal Government has stated that it intends to dedicate a significant portion of the $500 million transmission expansion fund provided in the NEP to the Maritimes portion of the TQM system to ensure that the producers will not have to assume an unfair share of start-up costs of the Maritimes pipeline. The Board will require that the Applicant submit the details of any financial contributions by the Federal Government towards the capital cost or operating cost of the pipeline. No tariff proposals were advocated that appear to be contrary to generally accepted regulatory principles. However, no decision on tariff matters is required in these certificate proceedings, nor is the Board determining any of these matters at this time.

8.3 Financial Plan

Evidence of the Applicant. TQM proposed project financing for the pipeline.

TQM stated that it would arrange the debt funding of the project through capital markets in Canada and the United States. Initial debt funding was expected to be arranged

through Canadian banks with flexibility to incorporate long-term institutional debt at a later date. The security for this debt financing would be limited to the assets of the partnership and the revenue generated under the transportation contract. TQM testified that the financing arrangements would be of a non-recourse nature to NOVA and TCPL and that the debt would not be guaranteed by the sponsors.

The sponsors would provide the equity funds necessary to complete the construction of the pipeline facilities provided the following requirements were satisfied:

(1) approval by the Board of the TQM Transportation Agreement, in form and substance acceptable to TQM;

(2) approval in principle by the Board of the recovery of payments made by TCPL under the TQM Transportation Agreement in the rates, tolls and charges of TCPL in form and substance acceptable to TCPL; and

(3) receipt of all necessary government and regulatory approvals required to commence construction of the pipeline facilities in form and substance acceptable to TQM. These approvals included:

(a) a certificate of public convenience and necessity,

(b) approval by the Board of plans, profiles and books of reference,

(c) signed contracts with the distributors, and

(d) leave to construct.

TQM indicated that it would expect to have something like the projected fourth year volumes under contract with the distributors before authorization to construct could be obtained from the Board.

TQM stated that the financial viability of the project would be primarily determined by the revenues generated pursuant to the gas transportation contract and by the credit-worthiness of the shipper.

Views of the Intervenors. IPAC recommended that a certificate should include a condition requiring that financing be secured before construction begins.

Views of the Board. Project financing is dependent on sales, purchase, and transportation contracts. In the Board's view, when these are in place the project will be financeable. The certificate to be issued to TQM will require it to satisfy the Board that appropriate arrangements for financing the project have been made before construction commences.

CHAPTER 9

ECONOMIC ASSESSMENTS

9.1 Net Economic Benefits

Evidence of the Applicant. TQM relied on the estimate of net economic benefits filed as evidence by Q & M in its earlier application in which it estimated the net economic benefits to Canada of gas expansion into both Quebec and the Maritimes by evaluating the combined project as compared to the alternatives of:

(1) deferring production now to meet domestic requirements beginning in 1993 ("shutting-in" production); and

(2) exporting the gas to the United States beginning in 1981.

The results of the Q & M analysis in the previous application indicated net economic benefits to Canada of $456 million (1979 dollars, discounted at 10 per cent to 1978) for the combined TCPL and Q & M project for 21 years as compared to the first alternative and a net economic cost to Canada of $2.8 billion when compared to the second alternative.

Views of the Intervenors. Nova Scotia assessed the net economic benefits to Canada of expanding natural gas sales to the Maritimes market by evaluating the direct costs and benefits associated with the project over a period of 19 years beginning in 1982. No alternative markets for natural gas were considered.

The direct net economic benefits based on the above assumptions were estimated to be $1.8 billion, (1980 dollars discounted at 10 per cent to 1980).

Nova Scotia stated that indirect benefits such as security of supply, increased employment and costs such as reduced employment in the refining sector were also attributable to the project but had not been estimated.

Views of the Board. As part of its appraisal of the evidence, the Board undertook its own cost-benefit analysis of the TQM project based on the evidence in these proceedings and its general knowledge.

The conceptual approach adopted by the Board was to identify first the costs and benefits that would result if the project went forward. The Board then estimated the costs and benefits that would result if the project were not undertaken but the relevant gas volumes were either used at some later date in Canada or were exported (on the same schedule as would apply to the project). The annual net benefits of the project were calculated as the difference between the annual cash flows that would result if the project proceeded, and the annual cash flows that would occur if the gas were used in either of the two alternatives (used later in Canada or exported). The period of analysis is from 1982 to 2000.

Generally the approach considers the quantifiable economic benefits and costs from a national perspective. The principal benefits include the economic value associated with displacing imported oil with natural gas and the sale of natural gas by-products.

The principal costs are the costs of construction and operation of transmission and distribution pipelines, conversion of oil burners and other equipment and the costs of producing the gas.

Against the first alternative of exporting the gas at, say, Emerson, Manitoba, the estimated net economic effect of the project would be a loss of about $1.1 billion (1980 dollars, discounted at 10 per cent to 1980). However, the gas to be used by the project has been set aside for Canadian use by being protected under the Board's surplus tests pursuant to the requirements imposed in Section 83 of the Act for the Board to make due allowance for "the reasonably foreseeable requirements for use in Canada" before natural gas can be declared surplus. Notwithstanding this, the estimate is noteworthy because it indicates the scale of pure economic

cost to Canada associated with the TQM project.

Against the second alternative of using the gas at some later date in Canada, the estimated net economic benefits to Canada of the proposed project are some $1.5 billion (1980 dollars discounted at 10 per cent to 1980). The Board views this estimate as the appropriate starting point for decision making, since it has already set the gas aside for Canadian use.

Accordingly, Table 9-1 lists the components making up the estimated net economic benefits. As is the usual Board practice, the calculation is shown at alternative discount rates. The estimated net economic benefits to Canada remain significant over the range of discount rates.

For the Board's estimates, the TQM pipeline capacity is assumed to be reached by 1991, and world oil prices in real terms are assumed to increase at 2 per cent per year from 1982 to 1985 and 1 per cent per year from 1986 to 1990 and to remain constant thereafter. The Applicant's estimates of transmission, distribution and conversion costs were adjusted to take into account the Board's forecast of demand and to exclude transfer payments (e.g., income and municipal taxes).

The estimate of net economic benefits is significantly higher than that contained in the April 1980 Reasons for Decision because of the increased international oil prices and the higher forecast of gas sales in the Maritimes.

Another way of stating this estimate of net economic benefits is by a comparison between the real cost, excluding transfer payments, of delivering domestic natural gas and the cost of providing light and heavy fuel oil derived from imported crude oil. Consistent with the assumptions underlying the foregoing estimates of net economic benefits, the Board estimates that the long-run average cost of delivering natural gas would be about $3.50/GJ (1980 $) compared to a cost of some $7.20/GJ for light and heavy fuel oil based on projected world oil prices.

However, it must be stressed that the above estimates of net economic benefits and of the long-run average

Table 9-1

Summary of the Board's Estimates of

Net Economic Benefits of the TQM Project
(Millions of 1980 dollars, discounted to 1980)

	Discount Rates		
PROJECT BENEFITS	5%	10%	15%
Value of Displaced Energy	4,338	2,622	1,695
Value of By-Products	728	445	291
Oil Storage Cost Saving[1]	68	55	44
Pollution Cost Saving[2]	31	19	13
	5,165	3,141	2,043
PROJECT COSTS			
Producers[3]	593	348	220
AGTL	40	24	16
TCPL (upstream to Lévis/Lauzon)	239	185	146
TQM (downstream from Lévis/Lauzon)	452	364	304
Distributors	357	263	203
Conversion	89	70	57
Gas Reserve Adjustment	1,374	333	92
	3,144	1,587	1,038
NET ECONOMIC BENEFITS OF THE PROJECT	2,021	1,554	1,005

1. Represents the saving associated with the lower inventories of crude oil and refined petroleum products required due to natural gas market penetration.

2. Represents the saving in pollution costs which would otherwise have been incurred through the continued use of fuel oil.

3. Includes the increased costs to Canadians of having to replace currently depleting gas fields with higher-cost conventional supplies and eventually with frontier supplies sooner than would be the case without eastern market expansion.

cost of delivering gas to the Maritimes assume that TQM will proceed without delay and without cost overrun, and that the Board's gas demand forecast, including thermal demand, will be realized on schedule as projected. In addition, the Board notes that costs associated with oil refinery investment, which may be induced through gas market expansion, are particularly difficult to quantify. This is partly because of uncertainties over the future quality of refinery feedstocks, but also because some proportion of refinery investment can usually be attributed to replacement of aging assets or to diverse changes in desired product quality. In the present instance, moreover, decisions on process and equipment have yet to be made and available choices involve highly differing capital costs.

On the other hand, these estimates exclude any measure of benefits to Canada from additional security of energy supply resulting from TQM.

The Board estimates that, if the forecast thermal demand could not be realized, or if the project were delayed for two years, the net economic benefits in Table 9-1 would decrease to $1.3 and $1.1 billion, respectively. If both of these were to occur, the net benefits would decline to just over $900 million. If real costs for transmission and distribution facilities east of the Alberta border were to double, the net benefits would decrease from $1.5 billion to about $700 million which indicates that the average long-run cost of delivering the gas would be some $5.85/GJ. Furthermore, should delay in construction occur, gas not be used for thermal generation and cost overruns of 100 per cent occur in combination, the net economic benefits would be drastically reduced to about $200 million. This means the long-run cost of delivering the gas would be approximately the same as the cost of fuel oil based on projected world oil prices.

However, these estimates do not include the value to Canada of difficult-to-quantify benefits such as additional security of energy supply, more diversity of consumer energy choices in eastern Canada, any reduction in regional income disparities, and the advantage of earlier development of

markets and facilities for marketing of new offshore gas. In particular, the Board believes that the potential benefits from improved security of energy supply could be substantial.

With respect to the impact of the project on Canadian consumers in general, the Board estimates that crude oil displaced by TQM would mean a saving in oil import compensation payments in the range of $1.2 to $2.4 billion (current dollars) in the period 1982 to 1990. These would lower petroleum compensation charges in the oil prices paid by the consumer. Furthermore, gas consumers in the Maritimes would be better off through paying lower energy costs than if they continued to use oil.

9.2 Economic Viability

Introduction. Economic viability analysis assesses, from the perspective of each of the major participants (i.e., the distributors, transmission company and the producers), the ability of the project to generate sufficient cash flow to cover project costs. Because TQM stated that the viability of the transmission company would be determined by the revenues generated pursuant to the gas transportation contract and by the credit-worthiness of the shipper, the focus of the analysis is on the ability of the distributors to recover their cost of service and cost of gas and on the ability of the producers to recover their costs by revenues generated from the sale of natural gas.

Evidence of the Applicant

Transmission and Distribution System Viability. TQM stated that the viability of the transmission and distribution system would be assured if the following measures were put in place:

(1) extension of the eastern zone to include the Maritimes;

(2) the implementation of oil and natural gas pricing ratios as outlined in the NEP;

(3) adequate market development bonuses to meet any revenue deficiencies experienced by distributors;

(4) conversion grants for residential and commercial customers; and

(5) selling gas to the distributor at prices based on an 85 per cent load factor even when the market load factor was lower thus providing storage facilities or its equivalent to the distributor free of charge.

TQM acknowledged that item (5) would have to be determined in a rate hearing under Part IV of the National Energy Board Act. Under cross-examination TQM agreed that if the cost of storage facilities were not incorporated into its rate base, the distribution system deficiency would increase.

Assuming implementation of the above-noted measures, TQM estimated that the distributors would experience a revenue shortfall of $50 million over the period 1982 to 1986 and would break even in 1987. This is illustrated in Table 9-2. This estimate of the distribution system deficiency would increase by some $7 million if the distributor were to pay for storage.

During cross-examination TQM also acknowledged that the distribution system deficiency had been underestimated to the extent that:

(1) the estimated cost of gas to the distributor did not include the impact of any additional upstream facilities required to move the TQM volumes; and

(2) the carrying cost of gas in storage was excluded.

Deficiencies for distributors were expected to be lower in New Brunswick than in Nova Scotia due to lower sales and higher costs in the latter Province.

TABLE 9-2

TQM ESTIMATE OF DISTRIBUTION SURPLUS/DEFICIENCY

	UNITS	1982	1983	1984	1985	1986	1987	1988	1989	1990
1. Cost of gas										
(a) Eastern city gate price at 85% load factor	($/GJ)	3.31	3.75	4.27	4.91	5.80	6.80	7.80	8.80	9.80
(b) Distributor's cost of service	($/GJ)	3.39	3.49	3.04	2.43	2.18	2.10	2.11	2.11	2.16
(c) Burner tip cost of gas (a + b)	($/GJ)	6.70	7.24	7.31	7.34	7.98	8.90	9.91	10.91	11.96
2. Price of natural gas required to achieve TQM demand forecast	($/GJ)	4.44	5.15	6.11	6.95	7.92	8.90	10.18	11.52	12.93
3. Distribution system unit deficiency/surplus (2-1(c))	($/GJ)	(2.26)	(2.09)	(1.20)	(0.39)	(0.06)	0	0.27*	0.61	0.97
4. Annual sales volumes	(PJ)	.86	6.56	17.55	30.81	42.77	53.73	62.21	68.73	73.34
5. Distribution system annual deficiency/surplus (3 X 4)	$MM	(1.94)	(13.71)	(21.06)	(12.02)	(2.57)	0	16.80*	41.93	71.14

* This assumes distributor will be permitted to sell gas at prices higher than the burner tip cost after 1988.

Source: Exhibit 250.

TABLE 9-2

TQM ESTIMATE OF

DISTRIBUTION SURPLUS/DEFICIENCY

	UNITS	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
1. Cost of gas											
(a) Eastern city gate price at 85% load factor	($/GJ)	11.42	12.70	13.99	15.34	16.50	17.77	19.13	20.60	22.19	23.91
(b) Distributor's cost of service	($/GJ)	2.21	2.31	2.37	2.44	2.52	2.61	2.71	2.83	2.95	3.09
(c) Burner tip cost of gas (a + b)	($/GJ)	13.63	15.01	16.36	17.78	19.02	20.38	21.84	23.43	25.14	27.00
2. Price of natural gas required to achieve TQM demand forecast	($/GJ)	15.02	16.81	18.50	20.10	21.48	23.02	24.66	26.42	28.34	30.41
3. Distribution system annual deficiency/surplus (2-1(c))	($/GJ)	1.39	1.80	2.14	2.32	2.46	2.64	2.82	2.99	3.20	3.41
4. Annual sales volumes	(PJ)	77.40	77.40	77.40	77.40	77.40	77.40	77.40	77.40	77.40	77.40
5. Distribution system annual deficiency/surplus (3 X 4)	$MM	107.59	139.32	165.64	179.57	190.40	204.34	218.27	231.43	247.68	263.93

Source: Exhibit 250.

The Applicant suggested that any revenue deficiencies experienced by the distributor should be met by the market development bonuses envisaged in the NEP. To ensure aggressive marketing by the distributor the Applicant also suggested that the Federal Government partially reimburse the demand charge through the market development bonuses at an estimated cost of $23 million over the early years of the project. The Applicant recognized that the market development bonuses were subject to provincial commitment to the 10 per cent target for non-transportation use of oil.

Impact on Producers. TQM's stated policy was that producers should not have to bear a disproportionate share of the cost of the project. Rather, there should be a sharing of costs by those benefitting, that is, producers and the governments of Alberta, Nova Scotia, New Brunswick and Canada.

TQM estimated that if no assistance was forthcoming for the transmission system the ensuing drop in the Alberta border price would mean a decrease in total revenue at the Alberta border and negative netbacks at the field gate for the Maritimes volumes between 1982 and 1985. This is summarized in Table 9-3.

As discussed previously in Chapter 8, the Applicant introduced a proposal whereby incremental field-gate revenue, and, by implication, the corresponding Alberta border price, from TQM sales should never be negative and in fact should approach 70 per cent of average field-gate revenue from domestic sales in the Toronto-Montreal service area to allow an equitable return to the producer.

The impact of TQM's proposal would be to increase producer revenues in the early years and reduce them in later years. The result in terms of producer revenues of adopting these measures is summarized in Table 9-4. TQM believed that its proposal would address the concerns of natural gas

Table 9-3

TQM ESTIMATE OF

IMPACT ON TOTAL REVENUE TO THE PRODUCER SECTOR

(Current Dollars)

YEAR	INCREMENTAL REVENUE AT ALBERTA BORDER*		INCREMENTAL REVENUE AT FIELD GATE**	
	($MM)	($/GJ)	($MM)	($/GJ)
1982	-6	-5.36	-6	-5.54
1983	-48	-5.45	-50	-5.63
1984	-61	-2.85	-65	-3.04
1985	-47	-1.29	-54	-1.48
1986	13	.25	2	.04
1987	94	1.50	78	1.25
1988	194	2.65	172	2.35
1989	293	3.54	266	3.21
1990	380	4.40	348	4.03
1991	525	5.80	489	5.40
1992	620	6.85	580	6.41
1993	719	7.94	676	7.47
1994	820	9.06	774	8.55
1995	904	9.99	855	9.45
1996	996	11.00	944	10.43
1997	1093	12.07	1037	11.46
1998	1198	13.23	1140	12.59
1999	1321	14.59	1259	13.91
2000	1415	15.63	1351	14.92

* Incremental revenue at the Alberta border is that revenue resulting from expansion beyond Quebec City. The revenue was determined by taking the total volume of gas leaving Alberta for Canadian use times the Alberta border price plus the total volume of exports times the export price less the weighted average tariff to the export points.

** Incremental revenue at field gate equals incremental revenue at the Alberta border less Alberta cost of service.

SOURCE: Exhibit 14, Fig. 4.D.1-8, & P. 4.D.1-5

Table 9-4

TQM ESTIMATE OF
IMPACT ON TOTAL REVENUE TO THE PRODUCER SECTOR WITH SUBSIDY AND COST OF SERVICE ABATEMENT

(Current Dollars)

Year	Alberta Border Price	Maritimes Volume - Sales & Fuel	(1) x (2)	Adjusted Maritimes Cost of Service	TQM Incremental Revenue at Alta. Border	Column (5) as a percentage of Column (3)
		PJ	$MM	$MM	$MM	%
	(1)	(2)	(3)	(4)	(5)	(6)
1982	1.86	.86	1.6	.6	1.0	63
1983	1.96	6.56	12.9	9.6	3.3	26
1984	2.37	17.55	41.6	15.1	26.5	64
1985	2.91	30.99	90.2	19.1	71.1	79
1986	3.67	45.23	166.0	36.4	129.6	78
1987	4.53	54.03	244.8	62.5	182.3	75
1988	5.38	62.60	336.8	83.9	252.9	75
1989	6.22	71.51	444.8	106.5	338.3	76
1990	7.05	74.02	521.8	125.2	396.6	76
1991	8.44	78.20	660.0	129.9	530.1	80
1992	9.53	78.20	745.2	132.7	612.5	82
1993	10.64	78.20	832.0	190.6	641.4	77
1994	11.76	78.20	919.6	190.0	729.6	79
1995	12.71	78.20	993.9	189.8	804.1	81
1996	13.76	78.20	1076.0	190.1	885.9	82
1997	14.87	78.20	1162.8	191.0	971.8	84
1998	16.07	78.20	1256.7	192.4	1064.3	85
1999	17.36	78.20	1357.6	194.7	1162.9	86
2000	18.76	78.20	1467.0	197.3	1269.7	87

(1) Alberta Border Price assuming Maritimes Volumes sold in Montreal.

(2) Maritimes sales volumes plus fuel for the Maritimes pipeline.

(3) Column (1) X Column (2). The revenue from Maritimes sales assuming costs upstream of Montreal are treated on a rolled-in basis.

(4) Maritimes cost of service with the federal government subsidy proposal and cost of service abatement proposal made by the Applicant.

(5) Column (3) - Column (4). Producer Revenue from Maritimes Sales assuming costs upstream of Montreal are treated on a rolled-in basis and costs downstream of Lévis/Lauzon are treated on an incremental basis.

Source: Exhibit #352

producers. TQM stated it would accept a condition being placed on the certificate which would require fair and equitable pricing for the gas producers before construction could commence.

Federal Subsidy. The federal subsidy required to ensure the economic viability of the project from the distributors', transmittors', and producers' points of view was estimated by TQM to be approximately $700 million (current dollars), of which $300 million would be allocated to improve the producer netback. This estimate did not include conversion grants to the residential and commercial sectors envisaged in the NEP.

Views of Intervenors.

Transmission and Distribution System Viability. APMC stated that if the TQM project were evaluated on an incremental stand-alone basis it would clearly be uneconomic.

Consumers' stated that TQM had underestimated the size of the distribution system deficiency and noted that federal government policy was critical to TQM's sales forecast and the economic viability of its project. Consumers' argued that any certificate should be conditioned so that leave to construct be withheld until TQM had filed unconditional gas sales contracts. If a certificate were issued before specific measures of the NEP were in place, appropriate conditions must be attached and interested parties must be afforded an opportunity to participate in the determination of whether TQM had met the conditions imposed.

IPAC neither supported nor opposed the application, as it felt the project was being advanced by the Federal Government in terms of national interest and not as an economic stand-alone proposition.

ICG Brunswick estimated a distribution system deficiency of less than $10 million for New Brunswick in the early years.

ICG Scotia estimated the distribution system deficiency would be approximately $90 million for Nova Scotia. This was based on gas costs at an overall load factor of 52 per cent.

ICG Scotia stated that the viability of the distribution system in Nova Scotia depended on:

(1) a substantial proportion of market development bonuses being allocated to sales in the Province;

(2) a development rate to reduce the cost of gas to the distributor in the early years;

(3) the implementation of TQM's proposal to provide storage for the distributor; and

(4) removal of heavy fuel oil from the market.

New Brunswick stated that the Province would likely make the necessary commitment to reduce by 1990 the use of oil in the residential, commercial, and industrial sectors to no more than 10 per cent of total energy use in those sectors in order to qualify for market development bonuses. However, it was felt to be a difficult target to meet.

In light of the large sums of money required from the Government of Canada and the Government of Alberta, as well as from the producers and gas users, to make the TQM proposal viable, New Brunswick recommended that the financial return to the Applicant be tied to its performance in meeting costs, market forecast, and scheduling estimates. New Brunswick stated it was not considering providing any financial assistance to the TQM project.

Nova Scotia did not undertake its own estimate of project viability because it felt that with the extension of the eastern zone and distribution system incentives there would be no difficulty for the distributor. It stated that a figure of $101 million had been discussed with EMR for the distribution system in Nova Scotia. Nova Scotia stated it had made a commitment to comply with the off-oil policy of the NEP in order to qualify for market development bonuses, but the 10 per cent target might be difficult to attain.

Nova Scotia did not support the Applicant's suggestion that federal funds for the transmission expansion program be employed to service TQM's cost of debt. It argued that the money should be used instead to extend gas service to every part of the Province where it could be utilized.

For its part, Nova Scotia was not considering providing any financial assistance to the TQM project.

Ontario stated that it would support the TQM project if it was economically viable on a stand-alone basis. Ontario questioned whether the project was the best means of achieving the off-oil policy of the federal government.

Impact on Producers. APMC estimated the accumulated shortfall in producer revenue from gas sales in the Maritimes would be $1.2 billion by the year 2000. This estimate was based on the difference between the delivered cost of gas (present Alberta border price plus transportation tariffs to the Maritimes) and the price of alternative fuels in the Maritimes market.

With respect to an equitable sharing of the costs of the project, APMC stated that it would be prepared to support the application if certain conditions were attached to a certificate. APMC proposed that producers receive 75 per cent of the normal Alberta border price (less the Alberta cost of service) during the first five years that the gas is sold into markets to be served by this project. After the first five years, the producers would receive the full Alberta border price. The 75 per cent price would continue to apply to a quantity of gas equivalent to each annual incremental sale for a five-year period. APMC also proposed that the TQM cost of service not be taken into account in determining the Alberta border price. This proposal was said to be conditional on a mutually acceptable agreement being reached between the Government of Canada and the Province of Alberta on the pricing of domestic oil and gas. APMC stated that if these conditions were not attached to the certificate the application should be denied.

APMC noted that although TQM advanced the idea of sharing costs, the TQM proposal merely postponed TQM's profits. Accordingly, APMC recommended that TQM be required to share in the cost of the project as a condition of the issuing of any certificate.

CPA advocated the sharing of the cost of the transmission line between the federal government, the Applicant, producers and the consuming Provinces of Nova Scotia and New Brunswick. With respect to the federal government, CPA stated that a mechanism should be in place so that if estimated capital costs increase, or volumes are lower than anticipated, the contribution of the federal government would increase (above the $300 million suggested) by some amount. Lastly, CPA recommended that a certificate be conditional on all relevant provisions of the NEP being legislated prior to the granting of leave to construct. In the event that some provisions were not legislated, intervenors should be granted an opportunity to be heard.

IGUA submitted that any certificate issued by the Board should be conditional upon the implementation of those aspects of the NEP that would ensure the economic viability of the project.

IPAC felt that the Board must examine the project carefully to ensure that its costs and risks were shared fairly amongst the beneficiaries of the project. IPAC noted that 70 per cent of the Alberta border price might not be as attractive to producers as sales at discounted prices to petrochemical companies in the Province of Alberta since those sales involve short-term deliverability contracts. IPAC stated that until the NEP is firmly established an assessment could not be made to determine a fair contribution by producers to the costs of the project.

Should the NEB decide to issue a certificate, it was IPAC's position that the following conditions be met:

(1) that the federal government contribute at least $500 million present value dollars (rather than $300 million);

(2) that other relevant provisions of the NEP be in place before construction begins; and

(3) that a further hearing be held, at which producers might be heard in respect to the question of satisfaction of any of these conditions.

Norcen submitted that the issue of sharing of risks on an equitable basis between governments, producers, sponsors and customers should be the subject matter of a future hearing to address the economic viability of the TQM project. Norcen therefore recommended the adjournment sine die of the present hearing.

PanCanadian supported the views taken by APMC, CPA and IPAC concerning the interests of western Canadian natural gas producers and stated that the burden of economic support should be shared in an equitable manner by governments, producers and by the Applicant.

Views of the Board

Transmission and Distribution System Viability. The Board agrees with TQM's contention that the project would be economically viable if the measures outlined in the NEP, including a sufficient level of market development bonuses, are put in place. That is, the revenues in the marketplace from the sale of natural gas would be sufficient to recover the distributor's cost of service and the distributor's cost of gas.

The Board's natural gas demand forecast, which includes gas for thermal electric generation on an interim basis up to 1986, was used to arrive at the Board's estimate of the required level of market development bonuses to ensure distributors' viability. As shown in Table 9-5 the estimates indicate that while small deficits would be incurred in 1982, 1987 and 1988 requiring development bonuses, the other years show surpluses which could more than offset the deficits. Table 9-6 indicates that if natural gas were not used for thermal electric generation, $82 million dollars would be the Board's estimate of the level of required market development bonuses. The costs to the distributors include the impact of additional upstream facilities and the carrying cost of gas in storage.

To give an indication of the possible variability of bonus requirements, the Board notes that if the distributors'

TABLE 9-5

SUMMARY OF BOARD ESTIMATES OF
DISTRIBUTION SYSTEM SURPLUS/DEFICIENCY
(ASSUMING THERMAL VOLUMES)

	UNITS	1982	1983	1984	1985	1986	1987	1988	1989	1990	TOTAL
1. Cost of gas											
(a) Eastern city gate price at 85% load factor	$/GJ	3.31	3.78	4.31	4.97	5.86	6.85	7.86	8.86	9.87	
(b) Distributor's cost of service	$/GJ	3.87	.91	1.51	1.61	1.68	2.36	2.42	2.46	2.53	
(c) Burner tip cost of gas (a + b)	$/GJ	7.18	4.69	5.82	6.58	7.54	9.21	10.28	11.32	12.40	
2. Price of natural gas required to achieve Board demand forecast	$/GJ	4.44	5.15	6.11	6.95	7.92	8.90	10.18	11.52	12.93	
3. Distribution system annual deficiency (2-1)	$/GJ	(2.74)	.46	.29	.37	.38	(.31)	(.10)	.20	.53	
4. Annual Sales Volumes	PJ	.6	24.5	35.6	47.9	56.5	48.3	54.9	60.2	64.1	
5. Distribution system annual -deficiency (3 x 4)	$MM	(1.64)	-	-	-	-	(14.97)	(5.49)	-	-	(22.10)
-surplus		-	11.27	10.32	17.72	21.47	-	-	12.04	33.97	106.79

TABLE 9-6

SUMMARY OF BOARD ESTIMATES OF
DISTRIBUTION SYSTEM SURPLUS/DEFICIENCY
(ASSUMING NO THERMAL VOLUMES)

	UNITS	1982	1983	1984	1985	1986	1987	1988	1989	1990	TOTAL
1. Cost of gas											
(a) Eastern city gate price at 85% load factor	($/GJ)	3.31	3.78	4.31	4.97	5.86	6.85	7.86	8.86	9.87	
(b) Distributor's cost of service	($/GJ)	3.87	2.91	2.98	2.48	2.34	2.36	2.42	2.46	2.53	
(c) Burner tip cost of gas (a + b)	($/GJ)	7.18	6.69	7.29	7.45	8.20	9.21	10.28	11.32	12.40	
2. Price of natural gas required to achieve Board demand forecast	($/GJ)	4.44	5.15	6.11	6.95	7.92	8.90	10.18	11.52	12.93	
3. Distribution system annual deficiency (2-1)	($/GJ)	(2.74)	(1.54)	(1.18)	(.50)	(.28)	(.31)	(.10)	.20	.53	
4. Annual sales volumes	PJ	.6	7.5	18.0	31.2	40.6	48.3	54.9	60.2	64.1	
5. Distribution system annual -Deficiency (3 x 4)	$MM	(1.64)	(11.55)	(21.24)	(15.6)	(11.37)	(14.97)	(5.49)	-	-	(81.86)
-surplus		-	-	-	-	-	-	-	12.04	33.97	46.01

cost of service were to increase by 50 percent and gas were not used for thermal electric generation, the required level of market development bonuses would increase to some $460 million.

Impact on Producers. To assess the impact of the TQM project on the producer sector, the Applicant compared selling the gas in the Maritimes with the alternative of selling it in Montreal. While this approach illustrates the nature of the incremental economics of TQM it does not measure whether the producer sector would be economically better off with TQM than without it. In the Board's assessment, based on an incremental analysis, returns to the producers would be more reasonable under the Applicant's tariff abatement proposal whereby the federal government would pay interest charges and the Applicant would defer certain front-end costs.

Federal Subsidy. Based on the evidence, the Board estimates the size of the required total federal subsidy would be in the range of $700 to $1300 million (current dollars). As shown in Table 9-7, this includes the $595 million proposed by the Applicant for the transmission system, up to about $460 million for the distribution system assuming cost overruns, and $90 to $220 million for the conversion grants.

With respect to the Applicant's proposal calling for a substantial contribution by the Federal Government with respect to the transmission system, the Board has already mentioned in Chapter 8 that it will require TQM to submit to the Board the details of any financial contribution by the Federal Government towards the capital cost or operating costs of the pipeline. The Board has noted the concerns which were expressed by certain intervenors, mainly those representing producers' interests, with respect to the equitable sharing of the risks and costs of this project.

TABLE 9-7

SUMMARY OF BOARD ESTIMATES OF REQUIRED TOTAL FEDERAL SUBSIDY

(millions of current dollars)

	Transmission System	Distribution System	Oil to Gas Conversion	Total
High	595	460[1]	220[2]	1275
Low	595	-	90[3]	685

(1) Excludes thermal volumes and assumes a 50 percent increase in distribution costs.

(2) Government conversion grant of $800 per household assuming escalation from 1980 at the CPI and average marginal tax rate of 20 percent.

(3) Government conversion grant unescalated and average marginal tax rate of 30 percent.

CHAPTER 10
PUBLIC INTEREST AND OTHER MATTERS

10.1 Security of Supply

Evidence of the Applicant. TQM stated that provisions of the NEP in relation to the government's stated "off-oil" policy reinforced TQM's view that the proposed pipeline would greatly enhance Canada's security of supply. The Applicant pointed to the NEP's 10 per cent target set for non-transportation use of oil, the NEP's over-all objective of replacing imported oil supplies with indigenous natural gas, and the government's position that a natural gas pipeline will be built to serve the Maritimes as lending unquestionable support to TQM's application and the impact its proposal would have on Canada's energy security. TQM warned of the potentially serious impact the interruption of offshore crude supplies could have on eastern Canada and the role the gas pipeline would have in helping to eliminate this threat.

TQM also pointed out that security of supply can be supported by economic arguments particularly when the current and projected prices for offshore crude supplies and the corresponding compensation payments are considered. In support of its case the Applicant presented estimates of the annual imports of crude oil the pipeline would displace. Its projections indicated that the project would displace about 2000 cubic metres per day, or 4.6 per cent, of crude oil imports in 1985, approximately 5000 cubic metres per day, or 10.7 per cent, in 1990, and over 7000 cubic metres per day, or 13.9 per cent, by 2000. In the Applicant's view these were significant volumes and had a correspondingly positive benefit to Canada.

Evidence of Intervenors. IGUA questioned whether the pipeline as proposed was the best means of getting the Maritimes off oil. IGUA stated that imported crude would still be required to serve Maritimes markets, and it also felt

that Hibernia and Sable Island should be considered as alternative sources of supply that would ensure security of supply for Canada.

Ontario stated that security of supply could be improved in the Maritimes if an economic means could be found to make natural gas available to those markets. It questioned the ability of the TQM project to displace significant volumes of imported crude and therefore suggested that alternative schemes should be looked at.

New Brunswick supported the project as being in the public interest of the people of New Brunswick.

Nova Scotia strongly supported the pipeline project in light of what it termed the great importance to the social and economic wellbeing of the citizens of Nova Scotia relative to acquiring a secure supply of Canadian gas. The Province also warned of the possibility of oil supply interruptions due to unstable conditions in some OPEC countries, as well as the possible adverse effect higher world crude oil prices would have on the Canadian economy.

Nova Scotia submitted that the TQM project provided a real and necessary alternative required to achieve the off-oil policy of the federal government.

Views of the Board. The Board considers the question of security of supply to be central to its decision. The threat of an interruption in imported crude supply is real and such an interruption could seriously affect those provinces dependent on imported crude supply. In this regard the Board considers the elimination of possible supply interruptions as being of primary importance. The Board considers the TQM project to be an important means of protecting the Maritimes against possible interruptions in the supply of imported crude oil. The Board considers the contribution of the TQM project towards security of supply to be significant.

10.2 General Partnership Agreement and Mandatary

Evidence of the Applicant. Trans Québec & Maritimes Pipeline Inc. (referred to in this section as "TQM Inc.") is a company within the definition of that term in the National Energy Board Act. TransCanada and Q & M, also two companies within the definition of that term under the National Energy Board Act, at the time each hold 50 per cent of the issued and outstanding shares of TQM Inc.

TransCanada and Q & M have decided to enter into a "General Partnership Agreement", the General Partnership being formed for the development, planning, construction, ownership, operation, and maintenance of certain pipeline facilities, including the pipeline facilities applied for by TQM Inc. It is intended that TQM Inc. be appointed mandatary to manage and administer the Partnership and to carry on the "Business" in accordance with the General Partnership Agreement. In such capacity, TQM Inc. applied for a certificate of public convenience and necessity to construct and operate a pipeline from Lévis/Lauzon to Halifax, which facilities would be owned by the General Parternship through TQM Inc. as its mandatary pursuant to the General Partnership Agreement.

This type of arrangement has not previously been encountered for gas pipelines in Canada. The main reason given for it was that such an arrangement would facilitate the "project financing" scheme proposed for the applied-for facilities. Such a financing plan was said to carry certain advantageous tax features for the sponsors, TransCanada and Q&M.

Evidence was heard and assurances were given to the Board with respect to the compliance with the terms and conditions of a certificate, if issued, and with the provisions of the National Energy Board Act, should there be a need for the transfer of a certificate or the transfer of pipeline facilities.

As a collateral issue to the examination of the partnership-mandatary arrangement, the question of compliance with the Gas Pipeline Uniform Accounting Regulations was explored. Evidence was given that TQM Inc. would maintain records and prepare financial statements for itself and the Partnership.

Views of the Board. The Board will include conditions in the certificate which take account of the proposed arrangement for the construction, ownership, operation, and maintenance of the applied-for facilities.

The Board is confident that TQM Inc. will maintain its own records and books of accounts in accordance with the Gas Pipeline Uniform Accounting Regulations. The Board will attach a condition to the certificate to ensure compliance with the accounting instructions of the said Regulations by or on behalf of the General Partnership.

As a collateral issue to the examination of the partnership-mandatary arrangement, the question of compliance with the Gas Pipeline Uniform Accounting Regulations was explored. Evidence was given that TQM Inc. would maintain records and prepare financial statements for itself and the Partnership.

Views of the Board. The Board will include conditions in the certificate which take account of the proposed arrangement for the construction, ownership, operation, and maintenance of the applied-for facilities.

The Board is confident that TQM Inc. will maintain its own records and books of accounts in accordance with the Gas Pipeline Uniform Accounting Regulations. The Board will attach a condition to the certificate to ensure compliance with the accounting instructions of the said Regulations by or on behalf of the General Partnership.